Agenda Date: 7/25/03
Agenda Item: 2B

STATE OF NEW JERSEY
Board of Public Utilities
Two Gateway Center
Newark, NJ 07102
www.bpu.state.nj.us

ENERGY

IN THE MATTER OF THE VERIFIED PETITION OF JERSEY CENTRAL POWER & LIGHT COMPANY FOR REVIEW AND APPROVAL OF AN INCREASE IN AND ADJUSTMENTS TO ITS UNBUNDLED RATES AND CHARGES FOR ELECTRIC SERVICE, AND FOR APPROVAL OF OTHER PROPOSED TARIFF REVISIONS IN CONNECTION THEREWITH	)	**FINAL ORDER** **DOCKET NO. ER02080506**
IN THE MATTER OF THE VERIFIED PETITION OF JERSEY CENTRAL POWER & LIGHT COMPANY FOR REVIEW AND APPROVAL OF ITS DEFERRED BALANCES RELATING TO THE MARKET TRANSITION CHARGE AND SOCIETAL BENEFITS CHARGE	)	**DOCKET NO. ER02080507**
IN THE MATTER OF THE CONSUMER EDUCATION PROGRAM ON ELECTRIC RATE DISCOUNTS AND ENERGY COMPETITION - JERSEY CENTRAL POWER & LIGHT COMPANY'S VERIFIED PETITION FOR DECLARATORY RULING	)	**DOCKET NO. EO02070417**
IN THE MATTER OF THE VERIFIED PETITION OF JERSEY CENTRAL POWER & LIGHT COMPANY FOR REVIEW AND APPROVAL OF COSTS INCURRED FOR ENVIRONMENTAL REMEDIATION OF MANUFACTURED GAS PLANT SITES AND FOR AN INCREASE IN THE REMEDIATION ADJUSTMENT CLAUSE OF ITS FILED TARIFF IN CONNECTION THEREWITH	)	**DOCKET NO. ER02030173**
IN THE MATTER OF JERSEY CENTRAL POWER & LIGHT COMPANY FOR INCREASES	)	

IN ITS LEVELIZED ENERGY ADJUSTMENT)
CLAUSE CHARGE AND DEMAND SIDE FACTOR) DOCKET NO. ER95120633

(SERVICE LIST ATTACHED)

BY THE BOARD:

This Final Order memorializes and provides the reasoning for the action taken by the Board of Public Utilities ("BPU" or "Board") in the above captioned matters, by a vote of five Commissioners at its July 25, 2003 public agenda meeting, which action was summarized in the Board's Summary Order dated August 1, 2003. This Final Order supersedes the Board's August 1, 2003 Summary Order.

TABLE OF CONTENTS

I. BACKGROUND AND PROCEDURAL HISTORY

This Order resolves the five above-captioned petitions filed by Jersey Central Power & Light Company ("JCP&L" or "Company"). These include:

1) BPU Docket No. ER02030173, filed on March 13, 2002, seeking a review and a change of rates in the Company's Remediation Adjustment Clause for the period of January 1, 1996 through July 31, 2003 ("RAC case");

2) BPU Dkt. No. EO02070417, filed on July 17, 2002, seeking a declaratory ruling by the Board concerning the prudency and recoverability in customer rates of the costs, plus interest, incurred in the Company's Consumer Education Program through July 31, 2002 ("CED case");

3) BPU Dkt No. ER02080506, filed on August 1, 2002, seeking changes to JCP&L's unbundled rate schedules ("base rate case"). This petition was filed in response to the Board's directive in its March 7, 2001 Final Decision and Order resolving JCP&L's Restructuring, Stranded Costs and Unbundled Rates filings. I/M/O/ Jersey Central Power and Light Company d/b/a/ GPU Energy – Rate Unbundling, Stranded Costs and Restructuring Filings, BPU Dkt. Nos. EO97070458, EO97070459, and EO97070460 ("Final Restructuring Order");

4) BPU Dkt. No. ER02080507, filed on August 1, 2002, seeking the resetting and recovery of its deferred Market Transition Charge ("MTC"), Societal Benefits Charge ("SBC") as well as its above-market Non-Utility Generation ("NUG") costs ("deferred balances case"); and

5) BPU Dkt. No. ER95120633, concerning the prudency of JCP&L's buyout of its Power Purchase Agreement ("PPA") with Freehold Cogeneration Associates, L.P. ("Freehold buyout case").

With respect to this fifth item, at its March 20, 2003 public agenda meeting, the Board voted to recall the issue of the prudency of the Freehold buyout from JCP&L's deferred balances case for direct hearing and disposition by the Board. On July 24, 2003, the parties to that proceeding, JCP&L, Board Staff ("Staff"), the Ratepayer Advocate ("RPA") and the Independent Energy Producers of New Jersey ("IEPNJ"), executed a Stipulation agreeing that the $135 million cost of the Freehold buyout, which had been previously authorized by the Board on an interim basis, subject to further review and refund, and which has already been fully recovered from JCP&L ratepayers, was reasonable and should be considered final with no further adjustment. At its July 25, 2003 public agenda meeting, as memorialized in its August 1, 2003 Summary Order, the Board voted to approve the Stipulation of the parties on this issue as a full and final settlement of this matter. The Board found that the Stipulation was a just, reasonable and efficient resolution of this matter and, accordingly, adopted the Stipulation as a full and final resolution of the Freehold buyout case. In this Final Order, the Board **HEREBY REAFFIRMS** its findings in this matter embodied in the Summary Order dated August 1, 2003.

JCP&L filed a motion to consolidate the first four petitions with the Board on August 1, 2002. These petitions collectively request Board approval of proposed overall increases and/or other adjustments to JCP&L's various unbundled tariff rates and charges for electric service effective for service rendered on and after August 1, 2003. These petitions were transmitted to the Office of Administrative Law ("OAL"), and assigned to Administrative Law Judge ("ALJ") Irene Jones.

Additionally, pursuant to the Board's Order dated July 22, 2002, Order Directing the Filing of Supplemental Testimony and Instituting Proceedings to Consider Audits of Utility Deferrals, Dkt. No. ER02050303, et al., an audit was performed on JCP&L's deferred balances, the results of which were placed in the record of the deferred balances case at the OAL.

These four matters now come before the Board on a record developed in hearings before the ALJ. Before considering the record that has been developed on these matters, a brief description of the events leading to these filings is provided below.

On February 9, 1999, the Electric Discount and Energy Competition Act, N.J.S.A. 48:3-49 et seq. ("EDECA" or "Act") was signed into law. Among other things, EDECA required the Board by Order to provide that by no later than August 1, 1999, each electric utility provide retail choice of electric power suppliers for all its customers, N.J.S.A. 48:3-53(a); unbundle its rate schedules, N.J.S.A. 48:3-52(a); reduce its aggregate level of rates for each customer class by no less than five percent, N.J.S.A. 48:3-52(d)(2); provide basic generation service ("BGS") at approved rates for customers who do not choose an alternate power supplier, N.J.S.A. 48:3-52(b); provide approved "shopping credits" to be deducted from the bills of customers who choose an alternate power supplier, N.J.S.A. 48:3-52(b); implement a Societal Benefits Charge to recover the cost of previously approved social, environmental, and demand side management ("DSM") programs, which were included in the utilities' bundled rates, N.J.S.A. 48:3-60(a); and (2) implement a Market Transition Charge to allow each utility the opportunity to recover an approved level of stranded costs, N.J.S.A. 48:3-61.

Prior to the enactment of EDECA, the movement toward energy market competition was already underway. The New Jersey Energy Master Plan Phase I Report, released in March 1995, presented a vision for the State in which energy markets in New Jersey would be guided by market-based principles and competition. Thereafter, after conducting extensive proceedings, on April 30, 1997, the Board issued an Order adopting and releasing a report entitled: Restructuring the Electric Power Industry in New Jersey: Findings and Recommendations, BPU Docket No. EX94120585Y, dated April 30, 1997 ("Final Report," also referred to as the "Green Book"). The Final Report was submitted to the Governor and the Legislature for their consideration. In anticipation of restructuring legislation to be developed and enacted, the Board's April 30, 1997 Order directed each of the State's four investor owned electric utilities to make three filings by July 15, 1997. These filings included a rate unbundling petition, a stranded costs petition, and a restructuring plan.

On July 15, 1997, JCP&L filed verified petitions with the BPU setting forth its unbundling, stranded costs and restructuring proposals. The unbundling and stranded costs petitions were assigned BPU Docket Nos. EO97070458 and EO97070459, respectively, and were transmitted to the OAL and assigned to ALJ Diana C. Sukovich. The restructuring petition was assigned BPU Docket No. EO97070460, and was retained by the Board. After extensive hearings and briefing, ALJ Sukovich issued an Initial Decision on the unbundling and stranded costs issues on September 4, 1998. Hearings on all four utilities' restructuring petitions were held before the Board (chaired by Commissioner Carmen J. Armenti) in April and May 1998.

On February 11, 1999, shortly after the enactment of EDECA, the Board established guidelines and a schedule for the commencement of settlement negotiations among the parties in JCP&L's restructuring proceedings. Though all parties could not reach a comprehensive settlement, two proposed stipulations of settlement were filed with the BPU in March 1999. One proposed settlement ("Stipulation I") was executed by JCP&L and certain parties. An alternative settlement ("Stipulation II") was executed by the RPA and several other parties. After reviewing the entire evidentiary record, including the proposed settlements and comments of the parties with respect thereto, as well as the requirements of EDECA, the Board issued a Summary Order dated May 24, 1999. In the Matter of Jersey Central Power & Light Company d/b/a GPU Energy - Rate Unbundling, Stranded Cost and Restructuring Filings, BPU Docket Nos. EO97070458, EO97070459, and EO97070460 ("Summary Restructuring Order"). On March 7, 2001, the Board issued its Final Restructuring Order under the same caption. In these two Orders (collectively, "Restructuring Orders"), the BPU modified the ALJ's Initial Decision in light of subsequent developments, and found that the elements of Stipulation I, with significant modifications and clarifications, to address concerns raised by the parties, including the proponents of Stipulation II, provided an appropriate framework for a reasonable resolution to the unbundling, stranded costs and restructuring filings.

The Restructuring Orders directed JCP&L to implement an initial rate reduction of 5% effective August 1, 1999, pursuant to N.J.S.A. 48:3-52(d)(2), and to phase in additional rate reductions in 2000, 2001 and 2002, which exceeded the minimum 10% reduction for the fourth year of the Transition Period required by N.J.S.A. 48:3-52(d) and (j). Specifically, the Board modified the proposed rate reductions included in Stipulation I, to provide for additional phased-in reductions, directing that the aggregate level of rate reductions be increased to 6% effective August 1, 2000, and further increased to 8% effective August 1, 2001; and that the rates be further decreased effective August 1, 2002, to an aggregate level 11% less than the level of rates in effect as of April 30, 1997. Final Restructuring Order at 91. The Board further directed that the 3% incremental rate reduction during the fourth year of the Transition Period be accomplished by implementing Stipulation I's proposed 5% rate refund provided for in Stipulation I, offset by a 2% increase in the MTC. Id. The Board also concluded that it would be reasonable and appropriate to utilize the 1996 cost of service study ("COSS") for the basis of establishing the level of unbundled distribution rates. (Id. at 93).

The Board further found that recovery of the above-market costs associated with utility power purchase agreements ("PPAs") via the MTC was consistent with N.J.S.A. 48:3-61(a)(2); and recovery of above-market costs associated with NUG contracts, as well as costs associated with NUG contracts buyout payments via the MTC was consistent with N.J.S.A. 48:3-61(a)(3). The Board also concluded that any Levelized Energy Adjustment Clause ("LEAC") over or under-recovery balance, to the extent reasonably incurred, existing as of August 1, 1999, would be considered a restructuring-related cost/credit. The Board found it appropriate for deferred fuel costs to be recovered (or credited back to customers) via the MTC, in accordance with N.J.S.A. 48:3-61(a)(4). (Id. at 97).

The Board established shopping credits at levels higher than contained in Stipulation I, but lower than in Stipulation II, finding that it needed to strike a balance between the level of shopping credits estimated to be needed to stimulate the development of a competitive market and the Act's mandated level of rate reductions. The Board found that, as a matter of law, JCP&L was entitled to full and timely recovery of the prudently and reasonably incurred costs associated with the provision of BGS and utility and NUG PPA costs pursuant to its obligation to provide basic generation service under N.J.S.A. 48:3-57. (Id. at 112). The Board directed that, to the extent these costs, as realized, exceeded the recovery afforded by the regulated rates, JCP&L could defer recovery of the net excess amount of costs and to accumulate in a deferred account, together with interest on the unamortized balances and carry on JCP&L's balance sheet the deferred balances as a regulatory asset. Id. JCP&L was directed to make a filing no later than August 1, 2002, in order to allow the BPU to review and determine the amounts of any over or under-recoveries contained in the deferred accounts as discussed above, as well as to examine the proposed level of all rate components beginning August 1, 2003. (Id. at 102).

On July 22, 2002, the Board directed JCP&L and the other three electric utilities to include certain specific items in their base rate filings, including distribution charges, the other components of their unbundled rates, an accounting for the use of proceeds from the issuance of transition bonds, and the effect of such use on the utility's capital structure and costs underlying the rate of return claimed in the filing. Order Directing the Filing of Supplemental Testimony and Instituting Proceedings to Consider Audits of Utility Deferrals, BPU Docket Nos. ER0205303, EO97070461, EO9707462 and EO97070463, dated July 22, 2002. The Board also directed the electric utilities to file their respective deferred balance petitions by August 30, 2002, and to include actual data by months for the first three years of the Transition Period and projected data by months for the last year of the Transition Period, which was to be updated on a monthly basis as it became available. The Board stated that the deferred balances filings would be transmitted to the OAL for hearing, and that the ALJ assigned to each utility's deferred balances case would also preside over that utility's base rate case. The Board anticipated that the base rate and deferred balance cases would be litigated separately and then consolidated for purposes of rendering a single Initial Decision. (Id. at 10-11).

On July 31, 2002, Governor McGreevey convened, by Executive Order 25, a Deferred Balances Task Force to examine "the reasons why the deferred balances were accumulated, what mitigation steps utilities took to reduce deferred balances and how they ought to be addressed to best protect the interest of ratepayers, including an evaluation of the merits of securitizing deferred balances." The task force issued its report on August 30, 2002. On September 6, 2002, the Governor signed into law Senate Bill 869, containing certain modifications to EDECA, which would allow, but not require, the BPU to permit securitization of portions of the utilities' deferred balances, subject to certain conditions being met. N.J.S.A. 48:3-51 and 48:3-62.

On July 29, 2002, the Board issued a Request for Proposal to secure the services of an independent accountant/auditor/consultant to perform audits of all four utilities' deferred balance accounts, transactions and supporting calculations for the Transition Period. Request for Proposal to Perform Audits of the Deferred Balances of New Jersey's Four Electric Utilities, BPU Docket No. EX02060363 and EA02060365. The Board's overall objective was to obtain certified opinions as to whether the utilities' deferred balances were correct and included only those costs that were reasonable, prudently incurred, accurately calculated, correctly recorded and in compliance with all applicable Board Orders. Regarding prudence of BGS costs, the auditors were directed to determine, at a minimum, whether the utilities pursued a prudent procurement procedure for the acquisition of BGS and whether, when required, they purchased power at reasonable prices consistent with market conditions in the competitive wholesale marketplace and consistent with appropriate hedging techniques. The auditors were also directed to comment on the utilities' mitigation efforts with regard to above-market NUG contract costs during the Transition Period.

On October 2, 2002, Mitchell & Titus, LLP ("M&T") and Barrington-Wellesley Group, Inc. ("BWG") (collectively, "the Auditors") were engaged to perform the audit of JCP&L. The scope of the audit consisted of JCP&L's transactions during the Transition Period, as they impacted the deferred balance accounts. The audit was to be conducted in two phases, with Phase I entailing JCP&L's deferred balances from August 1, 1999 through July 31, 2002 and Phase II entailing deferred balances from August 1, 2002 through July 31, 2003.

Given the regulatory background summarized above, on March 13, 2002, JCP&L filed its 2002 RAC case for review of all actual and projected costs and expenditures, including related insurance recoveries, incurred and to be incurred by JCP&L relating to the environmental remediation of its former manufactured gas plant sites for the period from January 1, 1996 through July 31, 2003. The Company filed its CED case on July 17, 2002, concerning the prudency and recoverability in rates of its Consumer Education Program costs related to restructuring, through July 31, 2002. On August 1, 2002, JCP&L filed its base rate and deferred balances cases. JCP&L filed a motion to consolidate these four filings due to their interrelationship. The parties did not object to the granting of this motion.

The four petitions, collectively, requested Board approval of JCP&L's proposed overall increases in and/or other adjustments to JCP&L's various unbundled tariff rates and charges for electric service, including its Delivery Charges, its MTC, SBC (which include RAC and CED costs), and approval of proposed tariff charges and revisions, to become effective for service rendered on and after August 1, 2003. JCP&L's base rate and deferred balances cases requested increases to reflect the proposed elimination of bill credits implemented pursuant to EDECA as well as the recovery of BGS, PPA and other costs included in the MTC deferred balance, and Board approval of the reasonableness and prudency of the costs reflected in JCP&L's MTC and SBC deferred balances (including the deferred RAC and CED balances). JCP&L requested that its MTC deferred balance either be securitized and recovered over 15 years or, alternatively, that it be amortized and recovered over 4 years. JCP&L indicated that its request to securitize its deferred balances over 15 years or to amortize them over 4 years would result in increases to JCP&L's annual net operating revenues of approximately $153 million or $279 million, respectively, representing an overall average rate increase of approximately 7.8% or 14.3%, respectively, compared to the average actual rates in effect during the 12 months ending July 31, 2003.[1] JCP&L proposed an effective date for the increase of August 1, 2003, to coincide with the end of the four-year Transition Period approved by the Board in its Restructuring Orders, consistent with EDECA.

[1] This does not include the impact of reflecting actual BGS in rates on a going forward basis as of August 1, 2003.

On August 22, 2002, the Board transmitted JCP&L's four petitions to the OAL for hearings. On October 21, 2002, ALJ Irene Jones was assigned to preside over the four cases. By letter dated October 24, 2002, the BPU requested that the ALJ submit her Initial Decision by May 1, 2003, to enable the Board to render its decision by August 1, 2003.

ALJ Jones conducted a prehearing conference on October 31, 2002, in which counsel for the Company, and the statutory parties to the case, the RPA and Staff participated. Counsel for Co-Steel Sayreville, Inc. ("Co-Steel"), Green Mountain Energy Co. ("GMEC") and the IEPNJ also participated in the prehearing conference. A Prehearing Order on the base rate and deferred balance cases was issued on December 4, 2002, setting forth, among other things, the issues to be litigated and the schedule going forward. A Prehearing Order dated December 5, 2002, set forth the issues to be litigated and the schedule for the RAC case.

Throughout the course of the proceedings, various parties filed Motions to Intervene and/or Participate. The ALJ granted Motions to Intervene by Co-Steel, the New Jersey Commercial Users ("NJCU"), IEPNJ, New Jersey Transit Corporation ("NJT") and the United States Department of Defense and other Federal Executive Agencies ("DOD/FEA"). The ALJ granted participant status to Public Service Electric and Gas Company ("PSE&G"), Rockland Electric Company ("RECO"), PPL EnergyPlus ("PPL"), and GMEC.

Consolidated public hearings were held in Ocean and Monmouth Counties on December 10, 2002 and in Morris County on January 6, 2003. Further public hearings were held in Monmouth and Ocean Counties on March 13, 2003, and in Morris County on March 21, 2003.

ALJ Jones presided over evidentiary hearings in Newark on January 15, February 20, 21, 25-27, March 3-7, and 17-19, 2003. On March 18, 2003, the Board transmitted to the parties the Phase I Audit Report prepared by M&T and BWG. (Exhibits S-37 and S-38). Thereafter, a final evidentiary hearing was held on April 28, 2003.

On March 25, 2003, the BPU sent a letter to the ALJs hearing the various deferred balances cases notifying them of the BPU's decision to recall certain issues from these cases. For JCP&L, the Board indicated that the prudency of the Freehold buyout would be addressed in a pending BPU proceeding in Docket No. ER95120633. The Board also recalled issues related to the securitization/amortization of each utility's deferred balances. Specifically, the BPU recalled the issue of how much of the prudently incurred deferred balances should be securitized and how much should be amortized (and the appropriate length of the amortization and the interest rate). The Board also recalled the issue of how much of the prudently incurred deferred balances is legally eligible for securitization under EDECA. The Board directed the ALJs to make findings as to the level of prudently incurred deferred balances for each utility, and indicated that the BPU would establish a transitional amortization mechanism rate for such deferred balances between August 1, 2003, until such time as it decided the issue of securitization/amoritization and any authorized transition bonds were issued. The Board indicated that to the extent that the parties had made proposals for transitional deferral recovery in their cases, those portions of the record would be reviewed and decided by the Board as part of its final decisions in these cases.

The parties filed initial and reply briefs on May 7, 2003 and May 21, 2003, respectively, which addressed the issues of cost of capital, revenue requirement, depreciation, service reliability, cost of service/rate design, BGS and other MTC deferred balance issues, DSM, CED, RAC, other SBC deferred balances, and transitional deferral recovery.

On June 16, 2003, the parties to the RAC case, JCP&L, Staff and the RPA, filed with the ALJ a proposed Stipulation of Settlement ("RAC Settlement") resolving all contested issues in the RAC proceeding.

By letter dated June 27, 2003, JCP&L filed with the ALJ a non-unanimous proposed Stipulation of Settlement of the base rate, deferred balances and CED cases ("Joint Position"). The signatories to the Joint Position included JCP&L, Co-Steel, NJ Transit, DOD/FEA, NJCU, and IEPNJ. Significantly, Staff and the RPA were not signatories to the Joint Position, nor did they participate in settlement negotiations.

On July 2, 2003, ALJ Jones issued an Initial Decision in the RAC case recommending approval of the RAC Settlement ("RAC ID") and a second Initial Decision in the base rate, deferred balances and CED cases recommending approval of the Joint Position ("Joint Position ID").

No Exceptions were filed to the RAC ID. Exceptions were filed, however, to the Joint Position ID. On July 14, 2003, Exceptions were received from the RPA, and Staff, and comments in support of the Joint Position were received from JCP&L. By letter dated July 15, 2003, Co-Steel advised that it would not file Exceptions, but reserved its right to file a Reply to Exceptions. On July 21, 2003, Replies to Exceptions were received from the RPA, JCP&L, Co-Steel, and DOD/FEA. On July 22, 2003, NJCU filed a Statement in Support of Initial Decision. On July 23, 2003, the RPA filed a response to the Reply to Exceptions filed by JCP&L.

On August 1, 2003, the Board issued a Summary Order in the consolidated proceedings. The Board adopted the ALJ's RAC ID. However, the Board rejected the ALJ's Joint Position ID. The Board made summary findings on the various issues in base rate, deferred balances and CED cases based on its review of the record and indicated that a Final Order containing a fuller discussion of the issues and the Board's reasoning would follow.

On August 18, 2003, JCP&L filed with the Board a Motion for Rehearing, Reconsideration, and Partial Remand of the Board's August 1, 2003 Summary Order. Answers to JCP&L's Motion were filed on August 29, 2003, by the RPA and Staff. A letter Reply to Answers was filed by JCP&L on September 5, 2003. On September 8, 2003, the RPA filed a letter Motion asking the Board to disregard JCP&L's September 5, 2003 Reply to Answers or, alternatively, to establish a procedural schedule for the RPA to respond to JCP&L's assertedly improper filing of a Reply to Answers. By letter dated September 11, 2003, JCP&L responded to the RPA's September 8, 2003 Motion. On September 18, 2003, the RPA filed a letter in response to JCP&L's September 11, 2003 letter.

At its October 10, 2003 agenda meeting, as memorialized by a letter from its Secretary, dated October 20, 2003, the Board determined to hold JCP&L's motion in abeyance, pending the issuance of a Final Order. The Board indicated that JCP&L could renew or supplement its motion after the Final Order is issued.

II. RAC CASE

On July 2, 2003, ALJ Jones filed her Initial Decision approving the RAC Settlement executed by JCP&L, the RPA, and Staff. The RAC Settlement provided that:

(1) JCP&L will credit (write-off) $2,500,000 to the deferred RAC balance within 45 days after issuance of a final Board Order approving the RAC Settlement.

(2) The adjusted ending deferred RAC un-recovered balance, as of December 31, 2002, including certain accounting adjustments recorded after December 31, 2002, totals $678,396. The parties agree that this adjusted un-recovered balance was reasonably incurred and should be approved for recovery through the Company's Tariff Rider RAC, together with any other amounts determined to be recoverable through Rider RAC in a subsequent proceeding. This amount shall be reflected in the RAC factor effective June 1, 2004, subject to the $2,500,000 write-off.

Interest on JCP&L's over or under-recovered deferred RAC balance shall be calculated on a monthly basis upon the average of the beginning and ending monthly balances of deferred RAC costs, less accumulated deferred income taxes associated therewith, at a rate equal to the rate on seven-year constant maturity Treasuries as shown in the Federal Reserve Statistical release on or closest to August 1 of each year, plus 60 basis points. Interest shall be compounded annually on August 1 of each year, commencing August 1, 2004, by adding the accrued interest from the prior 12-month period to the principal balance on which interest is calculated. The interest shall be calculated on a prospective basis only, beginning 45 days after the issuance of a Final Order approving the RAC Settlement.

(3) Beginning in December 2003, JCP&L agrees to file for annual RAC rate reviews by the end of December of each year. Each such annual RAC filing will include actual data through November 30 and forecasted data for December of that year, including a true-up adjustment for the prior RAC period for forecasted recoveries from the prior RAC period. The forecasted December data of each year shall be updated to actual during the course of the annual review proceeding. The RAC balance as of December 31, 2002, shall be included in the amount that is approved for inclusion in the RAC factor on June 1, 2004, without further review of the expenses that are reflected in that balance.

(4) JCP&L's manufactured gas plant ("MGP") remediation expenditures incurred on and after January 1, 2003, shall remain subject to review by the RPA and Staff to determine their reasonableness and prudence. The parties agree that no party shall seek to apply any part of the internal non-MGP environmental cost allowances allowed in JCP&L's last base rate case as an offset to recovery of any otherwise reasonable MGP expenditures for the period from January 1, 2003 through July 31, 2003.

(5) The RAC Stipulation resolves all issues relating to the calculation of the JCP&L deferred RAC account through December 31, 2002.

No party filed exceptions to the RAC ID. At its July 25, 2003, agenda meeting, as memorialized in its Summary Order of August 1, 2003, the Board determined based on its review of the record in the RAC proceeding, as well as the RAC ID that the RAC Settlement was a just, reasonable and fair resolution of this matter and, accordingly, adopted the RAC Settlement and the RAC ID as a full and final resolution of the RAC case. In this Final Order, the Board **HEREBY REAFFIRMS** its findings in this matter embodied in the August 1, 2003 Summary Order.

III. BASE RATE, DEFERRED BALANCES, and CED CASES

A. Litigated Positions of The Parties

As noted above, on August 1, 2002, JCP&L filed its base rate and deferred balances petitions. In total, the Company's filings sought approval for an overall combined increase in rates of $153 million, or 7.8%, assuming approval of the securitization of its projected deferred balances over a term of 15 years. In the event that the Company did not receive authorization to securitize its projected deferred balances over 15 years, the Company's combined request would amount to an increase of $279 million, or 14.3%, assuming a 4-year amortization.[2]

Subsequent to its August 1, 2002 filings, JCP&L submitted amendments to its filings in the form of updates, based upon 12 months of actual data for the test year ended December 31, 2002. The updated filings proposed a combined overall increase in rates of $122 million, or 6.1%, assuming securitization of the Company's deferred balance. If securitization is not approved, the updated data proposed a combined overall increase in rates of $246 million, or 12.4%, assuming a 4-year amoritization.

JCP&L's filings were scrutinized during eleven days of hearings.[3] The RPA filed extensive testimony and briefs challenging many aspects of the Company's request. Staff raised numerous concerns in cross-examination and filed extensive briefs setting forth its recommendations with respect to cost of capital, revenue requirements, depreciation, service reliability, cost of service/rate design, deferred balances issues, and transitional deferral recovery. Other parties filed more limited testimony and briefs, generally limited to their particular narrow areas of concern, primarily as to the impact of JCP&L's filings on their particular tariffs. Extensive initial and reply briefs were filed by JCP&L.

A detailed discussion of the litigated positions of JCP&L, Staff and the RPA on the various issues is contained in the Discussion and Findings Section, infra.

B. Joint Position

By letter dated June 27, 2003, JCP&L filed with the ALJ a non-unanimous proposed Stipulation of Settlement of the base rate, deferred balances and CED cases ("Joint Position"). The signatories to the Joint Position were JCP&L, Co-Steel, NJ Transit, DOD/FEA, NJCU, and IEPNJ. Significantly, neither Staff nor the RPA signed the Joint

[2] See Footnote 1.

[3] Because of the technically complex nature of ratemaking proceedings, direct testimony is prefiled such that the hearings consist largely of cross-examination.

Position nor participated in the negotiations leading to the proposed settlement. A brief summary of the Joint Position follows.

1. Base Rate Issues

The Joint Position provides for an increase in revenues of $31 million on an annual basis effective for service rendered on and after August 1, 2003. This amount reflects a decrease in delivery revenues of $80 million on an annual basis and the elimination of the existing 5% bill credit and other adjustments to the Company's filed position. The Joint Position provides the Company with a total rate base of $2,017 million, with a 9.14% overall weighted average rate of return, and a 10.6% return on common equity. The capital structure utilized for purposes of setting the rate of return is 41.05% debt, 54% common equity, and 4.95% preferred stock. (Joint Position, ¶1,2,3).
.
The Joint Position provides for no change in the depreciation rates or methodology for annual up-dates for JCP&L's electric transmission, distribution, and general plant for financial reporting and ratemaking purposes. (Id. ¶4).

The Joint Position provides for a levelized revenue requirement of $8.8 million for the recovery of the accumulated restructuring transition costs, totaling $70.5 million over eight years. This includes the elimination of $0.7 million due to deferral of the New Jersey Clean Energy Program lost revenues. (Id. ¶5,6)

The Joint Position proposes that all issues, proposed indices and other metrics relating to measures of service reliability and performance should be considered in ongoing or future generic investigations or rulemaking proceedings, rather than in the instant proceeding. (Id. ¶7).

2. Deferred Balances Issues

The Joint Position reduces JCP&L's annual SBC revenues by $16.8 million effective for service rendered on and after August 1, 2003. The Joint Position expressly adopts the RAC Settlement with respect to the RAC component of the SBC. It also provides that to the extent the Board orders interim or permanent Universal Service Fund ("USF") or Lifeline Program costs, JCP&L will defer these and receive full and timely recovery thereof through its SBC for the full costs associated with these programs. The Joint Position specifies that the Nuclear Decommission Costs ("NDC") component of the SBC include recoveries associated with the Oyster Creek, TMI-1, Saxton, and TMI-2 nuclear power plants and that interest accrued during and after the Transition Period on these deferred balances will continue to be calculated on a net-of-tax basis. (Id. ¶8).

The Joint Position asserts that the MTC/BGS deferred balance through July 31, 2003, has been reasonably and prudently incurred, and would allow JCP&L to recover the entire amount on an interim basis over ten years. The Joint Position provides for an MTC factor of 11.935 Mils/kWh effective August 1, 2003. (Id. ¶9, 10a, Schedule SJG-6, Attachment 3).

The Joint Position provides that interest accrued on or after August 1, 2003, will be computed monthly on the net-of-tax deferred balances for all components of the MTC and SBC, and compounded annually. For deferred balances other than the RAC and the MTC/BGS deferred balance, the interest rate on or after August 1, 2003, will be based on two-year constant maturity Treasuries as shown in the Federal Reserve Statistical Release on or closest to August 1 of each year, plus 60 basis points. The rate applicable to the MTC/BGS deferred balance would vary depending on when and/or if the Board approves securitization of this balance. (Id. ¶10a, 11).

The Joint Position provides that from May 1, 2001 until the Board approves the protocols for measuring energy savings under the New Jersey Clean Energy Program, JCP&L will defer lost revenues based on the due energy savings as reported in the quarterly New Jersey Clean Energy Program Reports filed with the Board. JCP&L would receive full and timely recovery of the revenue deferrals through its SBC. Once approved by the Board, the protocols would be used to calculate lost revenues on a prospective basis. (Id. ¶12).

The Joint Position provides that JCP&L will continue to sell NUG power and the output of any generation assets that continue to be owned by JCP&L into the PJM Spot Market unless and until the Board determines that a different selling protocol is appropriate. (Id. ¶14).

3. CED Issues

The Joint Position provides that the total CED costs through July 31, 2002 are reasonable. (Id. ¶13).

4. General Tariff, Cost of Service and Rate Design Issues

The Joint Position provides that JCP&L's proposals with respect to (1) modifications of some of the terms and conditions in its Tariff for Service; (2) the elimination of Service Classification OTR and certain Riders, and (3) certain proposed fee changes (e.g., Reconnection Charge, Service Charge for final bill readings outside of normal working hours and Field Collection Charge) that JCP&L requested in its filing are reasonable and should be implemented. (Id. ¶15).

The cost of service methodology for use in the Company's future rate cases was not agreed upon. Accordingly, the Joint Position provides that any party may submit, as part of an appropriate future proceeding, an alternative cost of service methodology. A party to such proceeding is not obligated to rebut the methodology offered by another party to establish the justness and reasonableness of any particular methodology. (Id. ¶12).

The Joint Position modifies JCP&L's Commuter Rail Service Special Provision in the Tariff for Service Classification GT to provide that the week-day hours of 5:00 p.m. to 8:00 p.m. shall be considered off-peak for billing purposes for NJT. In addition, where traction power is supplied at high voltage (230kV) and such power is being provided during a limited period to supplant power normally supplied by another utility, that limited period shall be excluded for the purpose of determining billing demand. (Id. ¶18).

The Joint Position provides that, as of August, 1, 2003, JCP&L's Special Provision for DOD/FEA in the Tariff for Service Classification GT will provide a credit against distribution kW and kWh charges and will be calculated so as to provide an overall reduction in charges to DOD/FEA customers. The aggregate reduction will be $3.367 million on an annual basis, based on 2002 usage, as compared with rates in effect on

January 1, 2003, after taking into account the effects of the lower charges for Service Classification G and the credit. (Id. ¶21).

The Joint Position further provides that upon the expiration of Co-Steel's existing contract for service on April 1, 2004, Co-Steel will be served as a Service Classification GT customer. Co-Steel will be subject to all provisions and charges provided for in Service Classification GT except that: (1) the Distribution Charge for Co-Steel will be $1.87 per kW based only on the actual maximum monthly 60-minute demand for the current billing period, whether on-peak or off-peak; (2) the distribution KVAR charges will not be applied to Co-Steel, and (3) an MTC credit of $0.009844 per kWh will be applied to all kWh usage for Co-Steel. (Id., ¶22).

The Joint Position provides that the rate design for the demand (kW) charge component of the delivery charge will be modified to eliminate intra-class customer impact disparities between commercial and industrial customers. Service Classification GST customers will have an increase in the tariffed monthly Customer Charge of $11.54 and $16.47 for single-phase and three-phase, respectively. All other tariffed monthly Customer Charges will remain unchanged. (Id.,, ¶23).

The parties to the Joint Position agree that the underlying principle of ratemaking should be the gradual elimination over time of interclass subsidies so that the "unitized rate of return" for all classes will be 1.0. JCP&L agrees to adopt and support this gradual approach to "unity" in future proceedings. (Id., ¶24).

C. Initial Decision on Joint Position

On July 2, 2003, ALJ Jones issued a short Initial Decision recommending adoption of the Joint Position as filed. The ALJ found that the parties to the Joint Position had voluntarily agreed to its terms and summarily concluded that the Joint Position represented a fair and reasonable resolution of all issues in these cases. The ALJ did not make any specific findings with respect to the individual issues which were developed in the record before her. The ALJ noted that neither Board Staff nor the RPA were signatories and that, in view of time constraints imposed by the BPU and the August 1, 2003 deadline for new rates to go into effect, any objections thereto should be submitted to the Board as Exceptions.

D. Exceptions

1. *JCP&L*

JCP&L filed Comments in Support of the Initial Decision, asserting that the Joint Position represents a fair and balanced resolution of all issues raised in the base rate, deferred balances and CED proceedings. JCP&L notes that the ALJ in her Initial Decision called the Joint Position "fair and reasonable." (JCP&L Exceptions at 3). JCP&L admits that the signatories to the Joint Position did not include Staff or the RPA, and asserts that neither Staff nor the RPA participated in the settlement discussions, although they were invited to do so. (Id. at 2,6,7). JCP&L argues that even with the implementation of new BGS charges and the annual recovery of its MTC/BGS and SBC deferred balance components, the new overall rates as proposed in the Joint Position will result in customer bills that on average will not be greater than the July 1999 levels that prevailed prior to the start of the Transition Period under EDECA. (Id.. at 4, 20).

The Company asserts that the major impacts on its rates stems from two aspects of EDECA that the Company argues are beyond its control. First, JCP&L contends that the annual interim recovery of $67 million of its deferred balance reflected in the Joint Position is a result of the inadequacy of JCP&L's previously capped rates under EDECA to recover the full market costs of supplying BGS to its retail customers. Second, effective August 1, 2003, the new auction-based BGS rates that were previously approved by the Board will be substituted for the existing shopping credits which were set in the Restructuring Orders. These new auction based BGS rates will result in an average bill increase for fixed-price BGS customers of about 7.5%. (Id. at 4-5).

2. *RPA*

The RPA filed Exceptions comprised of two volumes spanning nearly 100 pages. The RPA asserts that: (1) neither the Staff nor the RPA participated in the settlement discussions nor were signatories to the Joint Position; (2) because only representatives of the Company's large energy users participated in the settlement discussions, and because these parties did not participate in the all aspects of the case, the Joint Position fails to represent the interests of the Company's residential and small business customers, who comprise the overwhelming majority of the Company's customers; and (3) the Joint Position lacks compromise because the signatories all received advantageous results very close to their litigated positions at the expense of residential and small business customers. (RPA Exceptions at 1).

As more fully discussed below, the RPA also took specific exception to a wide range of issues within the Joint Position. The RPA requests that the Board reject the ALJ's Initial Decision approving the Joint Position and adopt the positions advanced by the RPA at hearing.

a). Cost of Capital

The RPA urges the Board to reject the 9.14% overall rate of return in the Joint Position and instead, approve an overall rate of return of 808%. The RPA argues that its proposed 8.08% return is based on the only actual capital structure contained in the record. (RPA Exceptions, Vol. 1 at 6, 8 and 9). Unlike the Company's proposed stand-alone capital structure, the RPA asserts that its proposed consolidated capital structure guards against manipulation, is consistent with the practices of credit reporting agencies who do not solely rely on stand-alone capital structures in their evaluations, and properly passes savings from lower financing costs to JCP&L's ratepayers. (Id. at 9-10).

The RPA recommends that, as a component of the overall rate of return, the Board approve a 9.85% return on common equity, including an adjustment of 35 basis points in recognition of FirstEnergy's highly leveraged capital structure. (Id.. at 13-25).

b). Revenue Requirement

Rate Base: The RPA takes issue with the Joint Position's rate base of $2.017 billion. The RPA faults the Joint Position and the ALJ for failing to consider certain adjustments proposed by the RPA. Specifically, the RPA cites to modifications it proposed on the record to adjust certain components of the Company's Cash Working Capital and to reflect the benefit to the Company from the filing of a consolidated tax return. The RPA recommends that the Board adopt the RPA's proposed rate base of $1.914 billion. (Id. at 26-27).

Pro Forma Operating Income: The RPA proposes several adjustments to various components that comprise the Company's Pro Forma Operating Income, as follows:

Revenue Adjustments: The RPA recommends an increase of $4.684 million to the Company's test year revenues to account for an increase in the Company's residential and commercial customers. (Id. at 32-33).

Expense Adjustments: The RPA faults the Joint Position for not specifying the nature and level of the adjustments made to the Company's litigated positions regarding its expenses. The RPA requests that the Board adopt the adjustments made at hearing by the RPA to the following expenses: (Id. at 33).

Advertising: A disallowance of $958,000 in test-year expenses claimed by the Company for community affairs, public relations, and image advertising was recommended by the RPA.. (Ibid.)

BPU/RPA Assessment: Reduction of the Company's revenue requirement by $13,000 to reflect the reduction in the Company's rates following the completion of the rate case. (Id. at 34).

Charitable Contributions: Disallowance of $752,000 in charitable contribution expenses claimed by the Company. (Id. at 34).

Depreciation: Rejection of the Company's proposed annual net salvage expense of $43.1 million. (Id. at 44-51).

Management Audit: Reduction of JCP&L's management audit amortization allowance by $148,000. (Id. at 35).

Merger Costs: Rejection of $42.696 million in merger costs claimed by the Company. (Id. at 35-36).

SAP Project Evolution Amortization: Reduction of the Company's revenue requirement by $1.697 million for the costs associated with Project Evolution. (Id. at 36-37).

Rate Case/Regulatory Expenses: Modification of the Company's revenue requirement to reflect a 50/50 sharing of actual rate case expenses, amortized over a five-year period. (Id. at 37-38).

Regulatory Asset Amortization: Rejection of the Company's proposal to shorten the recovery period for certain production related assets with a corresponding reduction of $2.604 million to the Company's Operation and Maintenance ("O&M") expense. (Id. at 38).

Restructuring Transition Costs: Disallowance of a requested eight-year amortization of $70.5 million in certain restructuring related costs incurred in 1996, resulting in a net $8.8 million reduction to the Company's revenue requirement. (Id. at 38-39).

Incentive Compensation: Disallowance of $4.818 million for incentive compensation for JCP&L's employees. (Id. at 40).

Miscellaneous Expenses: Reduction of $186,000 to the Company's claimed test-year miscellaneous expense. (Id. at 40-41).

Interest Synchronization: Adoption of the RPA's proposed interest synchronization adjustment. (Id. at 41).

c). Depreciation

The RPA contends that JCP&L's ratemaking treatment for its estimated future net salvage results in an unreasonably large discrepancy between the proposed test-year depreciation expense that the Company seeks to recover for negative net salvage, and the actual amount expended for net salvage. (Id. at 44). The RPA argues that this mismatch stems from the Company's use of future inflation in estimating its net salvage expense which "relates cost of removal in current dollars to retirements in very old historical dollars, thus resulting in very high cost of removal estimates." (Id. at 45). The RPA recommends that the Board approve its net salvage allowance approach whereby an annual net salvage expense is calculated by averaging the past five years of actual net negative salvage expense, which is then added to the annual depreciation expense and included in the Company's revenue requirement.

The RPA also requests that the Board adopt a methodology whereby the cost for removing a retired asset be charged to the cost of its replacement. (Id. at 51). The RPA further urges that JCP&L be required to submit a detailed annual report to the Board and RPA showing all aspects of its annual deprecation rate update calculations. (Id. at 51-52).

d). Service Reliability

The Joint Position provides that the concerns over JCP&L's service reliability will be addressed in ongoing or future generic investigations and rulemaking proceedings. The RPA rejects this position and recommends that the Board act to address service reliability concerns by adopting the Service Quality Index and individual customer rebates as proposed by the RPA.

e). Rate Design

The RPA takes Exception to the Joint Position's modifications to JCP&L's current rate design.

1. Reconnection and Service Charges: The RPA asserts that increases to the current reconnection and service charges may unreasonably burden those ratepayers needing such services and that their derivation was not consistent with past Board practices. Thus, the RPA recommends that the Board reject the proposed increases and maintain the current levels of charges for these services. (Id. at 59-60).

2. Market Transition Charge: The RPA opposes the Company's proposal to recover MTC revenues through a methodology that the Board has historically applied to LEAC

under-recoveries. The RPA argues for maintenance of the current methodology used to recover MTC revenues because it (1) properly balances MTC responsibility among the Company's rate classes; (2) avoids any adverse impact to Company's Residential Service and General Service customers; (3) affords all rate classes an opportunity to benefit from competition, and (4) avoids substantial increases to some of the Company's rate classes. (Id. at 61-63).

3. Customer-Specific Rate Design Changes: The Joint Position provides for several modifications to the proposed rate design filed by the Company which are specific to the needs of those customers who were signatories thereto.

- Co-Steel: The RPA objects to allowing Co-Steel to bypass the MTC charge through the characterization in the Joint Position of the non-bypassable MTC charge as a credit. The RPA notes that EDECA imposes collection of the MTC from all electric public utility customers. Because Co-Steel is a customer of JCP&L, the RPA argues that there is no basis to allow Co-Steel to avoid its legal obligation to pay the MTC charge. (Id. at 63-65).

- NJT, DOD/FEA, NJCU: The RPA considers the Joint Position's provisions for NJT, DOD/FEA and NJCU as special treatment benefiting these entities and opposes these provisions, arguing that they were reached without consideration of the interests of the other classes of the Company's customers to counterbalance the litigation position of these parties. (Id. at 66-67).

- IEPNJ: The RPA criticizes the execution of the Joint Position by IEPNJ because it did not participate in any hearings and did not file any briefs in the proceeding. (Id. at 67).

f). BGS Procurement and Deferred Balances

The RPA urges the Board to reject the conclusion contained in the Joint Position that the Company's MTC/BGS deferred balance was reasonably and prudently incurred and the recommendation allowing rate recovery by the Company of the entire MTC/BGS deferred balance projected to be incurred through July 31, 2003. The RPA argues that JCP&L failed to meet its burden of proof that these costs were reasonable and prudently incurred. Comparing the large difference in deferred balances accrued by FirstEnergy affiliates in New Jersey and Pennsylvania, the RPA asserts that the Pennsylvania affiliates' incurred costs were about 12% lower or $239 million less than JCP&L's costs. (RPA Exceptions Vol. II, at 2-7). The RPA characterizes JCP&L's procurement strategies as ineffective and contends that JCP&L did not attempt to contain costs or adequately review its own procurement strategies. (Id. at 8-12). In addition, the RPA asserts that JCP&L's ignored use of financial or weather hedging as a means to reduce its risk to market fluctuations thereby increasing its exposure to price run-ups. (Id. at 13-14).

The RPA requests that the Board: (1) deny JCP&L rate recovery of $239 million of its deferred balance; (2) deny rate recovery of $59.463 million in interest collected on above-market NUG costs; (3) clarify whether the Company is including the balance associated with the Freehold Buyout in its interest calculation; and (4) disallow the Company's self-authorized collection of a 14.64% return on its generation assets through BGS revenues.

g). Clean Energy Program

The RPA opposes the provision within the Joint Position that allows the Company full recovery of "lost revenues" associated with the Board-approved Clean Energy Program ("CEP"). The RPA argues that although the Joint Position states that the proposed revenue requirement eliminates recovery of these lost revenues, the nature of the Joint Position makes it impossible to determine whether, in fact, the proposed rates include such a recovery. (Id. at 21-22). The RPA further opposes granting the Company guaranteed revenues of all lost revenues in the amounts claimed by the Company from May 1, 2002 through the effective date of a Board Order approving the protocols for determining energy savings. The proceedings seeking Board approval of the energy savings protocols are currently pending. The RPA argues that this provision is in direct violation of the Board's March 9, 2001 Order I/M/O the Petition of the Filing of the Comprehensive Resource Analysis of Energy Programs Pursuant to Section 12 of the Electric Discount and Energy Competition Act of 1999, BPU Docket No. EX99050347, which the RPA asserts allows recovery of lost revenues only through 2003, and only after Board approval of the protocols for measurement of the energy savings resulting from the CEP. (Id. at 22-27).

h). Consumer Education Costs

The RPA opposes the provision in the Joint Position that allows the Company to recover its total CED costs through July 31, 2002. The RPA argues that the record to the proceeding is devoid of any evidence in support of the Company's claim. Absent record support, the RPA asserts that the Board cannot make a determination as to the reasonableness and prudence of these costs and urges the Board to disallow their recovery. (Id. at 28-29).

i). Transitional Deferred Balances Recovery

The Joint Position proposes interim carrying charges on the Company's deferred balances that would vary depending on when the Board reaches a determination on the Company's securitization proposal. In addition, the Joint Position provides for alternative rates should the Board not approve the Company's securitization proposal. The RPA proposes to use a ten-year amortization period for the Company's deferred balance, with interest fixed at the seven-year treasury rate shown in the Federal Reserve Statistical Release on or closest to August 1, plus 60 basis points. The RPA argues that its proposal offers a less costly alternative to that submitted by the Company and urges the Board to adopt its proposal. (Id. at 30-31).

Staff

In lieu of formal Exceptions, Staff submitted a letter that voiced its continued support for the positions advanced by Staff during the proceeding. Staff further noted that the Joint Position was reached without its participation.

E. **REPLIES TO EXCEPTIONS**

1. JCP&L

a). Cost of Capital

The Company asserts that the Joint Position's capital structure, associated capital costs, return on equity of 10.6% and overall rate of return of 9.14% are well within the zone of reasonableness as supported by the record testimony of its three expert witnesses who testified on the issue, and that the Joint Position represents a reasonable compromise that should be adopted by the Board. (JCP&L Reply Brief on Exceptions at 7-9).

b). Revenue Requirement

Rate Base: The Joint Position provides for a rate base of $2,017 million, which the Company notes is $37 million less than the amount it supported in its 12+0 Update, and is virtually the same rate base amount ($2,016.3 million) recommended by Staff. (Id. at 10). JCP&L argues that the rate base proposed in the Joint Position fully recognizes Staff's position regarding consolidated income tax savings. JCP&L further asserts that the RPA's Cash Working Capital arguments have been repeatedly rejected by the Board in numerous prior cases. (Id. at 10-11).

Operating Income: Responding to the RPA's criticism that the Joint Position does not provide an explicit breakout of individual issues relating to JCP&L's pro forma revenues and expenses, the Company asserts that the Joint Position represents an overall compromise of all income and expense issues. (Id. at 11). JCP&L asserts that the lack of specificity of individual items in dispute is the same approach used in the settlement of the PSE&G rate proceeding that was recently approved by the Board without any objection by the RPA. (Ibid.). JCP&L further argues that the RPA overlooks the $80 million decrease in its delivery rates provided for in the Joint Position and asserts that this amount is nearly twice the $41.6 million decrease supported by the Company's 12+0 Update. (Ibid.).

c). Depreciation

JCP&L contends that, as proposed in the Joint Position, there should be no change in its existing depreciation rates and methodologies. These rates were reviewed and approved by the Board only after submission by the Company of a full-fledged depreciation study. There is no such study in the record of this matter before the Board. In the absence of a similar depreciation study, JCP&L maintains that an action by the Board accepting the type of modification as proposed by the RPA would be inappropriate. (Id. at 12). JCP&L further urges rejection of the RPA's proposal regarding the treatment of the future costs for removal of utility plant. JCP&L argues that the Board, FERC and the National Association of Regulatory Utility Commissioners have historically recognized inclusion of such costs as a proper element in current depreciation rates, and that this issue should only be decided in a proceeding where such removal costs are fully studied and analyzed on the basis of current forecasts and projections. (Id. at 12-13).

d). Service Reliability

In response to the RPA, JCP&L argues that: (1) Staff supports the Company's position on reliability issues, recommending that the RPA's issues should continue to be addressed in other reliability-related proceedings currently or prospectively before the Board; (2) the RPA is improperly attempting to use these proceedings to justify the imposition of a regulatory mechanism that would set service standards, a performance tracking mechanism, and penalties for failure to meet the standards because a base rate proceeding is not the appropriate vehicle in which to consider these issues, especially in light of the ongoing generic investigative and rulemaking proceedings that the Board has or will initiate under EDECA; (3) the RPA incorrectly asserts that the Company's testimony regarding capital investments made to further its reliability efforts, introduced the issue of reliability into this proceeding and that, by arguing that reliability should not be an issue in this proceeding, the Company sought to evade review of these capital investments; (4) the RPA neither challenged nor investigated any of JCP&L's reliability-related capital investments, and (5) the RPA's attempt to introduce into the Board's decision-making process hearsay newspaper accounts of recent outage events and materials that were not previously made part of the record to the proceeding raises due process concerns. (Id. at 13-17).

e). Rate Design

Special Charges: The Company disputes as unsupported the claims made by the RPA that increasing the Reconnection and Service charges will disproportionately burden the Company's needy customers. The Company reasons that, under cost of service principles, costs incurred by a utility for service should be the responsibility of the customer or customers who cause such costs, and that in cases where a customer is suffering financial hardship, the Universal Service Fund is the appropriate source of assistance. (Id. at 18-19).

Market Transition Charge: JCP&L contends that in accordance with EDECA, the Joint Position provides for the calculation of the MTC on a uniform, per kWh basis for all customers in all rate classes, subject only to regular voltage level adjustments and the special Co-Steel credit. Any other approach, the Company argues would denote favoritism or be discriminatory. (Id. at 19-20).

F). Basic Generation Service Prudence Review

JCP&L argues that the RPA's Exceptions repeat the same arguments raised in its briefs, which were responded to in the Company's reply briefs. Nonetheless, JCP&L reiterates its response to some of the key points raised by the RPA. (Id. at 21-25).

Pennsylvania vs. New Jersey Supply Costs: JCP&L rejects the RPA's arguments that because of the absence of a deferral recovery mechanism in Pennsylvania, JCP&L's Pennsylvania affiliates had a stronger incentive to control provider of last resort costs, as BGS costs were referred to in Pennsylvania. The Company argues that (1) it always knew that it would need to justify its costs in the context of a prudence review; (2) the unrefuted testimony of its witness at hearing demonstrates that both JCP&L and its Pennsylvania affiliates implemented the same power procurement methodologies, policies, and procedures; and (3) the record contains extensive evidence explaining the basis for the differences in average prices between New Jersey and Pennsylvania. (Id. at 25-26).

The Company's Procurement Models: JCP&L rejects the RPA's criticism of the Company's procurement models. JCP&L asserts that the RPA mischaracterized the various Company models and that the RPA's arguments on this issue are without merit and display a lack of understanding of real markets. JCP&L asserts that deviations by the Company from the models were affirmed by the Auditors as reasonable and prudent, and that the models were designed to reduce the Company's and its customers' level of risk exposure. (Id. at 27-30).

Weather Hedging: JCP&L asserts that the RPA's criticism of JCP&L for not purchasing weather hedges ignores the Company's reasons for not using weather hedges, namely that weather hedges are thinly traded, are of limited use, and are very costly. (Id. at 36).

Provision of Data: The Company argues that the RPA's complaints about a lack of data are unfounded and that no inference, adverse of otherwise, can be drawn from the Company's action, particularly in light of the substantial amount of data provided by the Company to the RPA. (Id. at 30-31).

Auditor Independence: JCP&L urges the Board to reject the suggestion by the RPA that the Auditors did not conduct an independent review and analysis of the Company's statements. The Company asserts that while the Auditors did on several occasions adopt language verbatim from materials supplied by the Company, the record shows that this was done only after the Auditors had independently verified their conclusions, and there was no reason why such language should not be used, particularly if the point had already been properly articulated by the Company. (Id. at 31-32).

g). Miscellaneous

JCP&L asserts that (1) the Freehold Buyout balance is not included in the deferred balance interest calculation; (2) the inclusion of a return of and on the investment in JCP&L's retained generation assets is consistent with the Final Restructuring Order which allows the Company to recover all of its costs associated with its owned generation assets, and (3) the RPA's proposed disallowance of $59.9 million of NUG-related interest costs raised for the first time in briefs is unsupported by the record, contrary to the conclusions of the Auditors, and unsupported by Staff. (Id. at 32).

h). Response to Staff's Exceptions

In response to Staff's Exceptions reiterating Staff's reliance upon its filed positions, JCP&L reiterated its reliance upon its filed positions, particularly with respect to Staff's attempt to bolster its position with extra-record evidence and to compare JCP&L's procurement activities to the prices obtainable on the PJM spot market, which prices the Company asserts would have been different had JCP&L and its affiliates purchased all of their requirements on the spot market. The Company alleges that such an approach would have mirrored the approach that led to the California energy crisis of 2000-2001. (Id. at 32).

i). Clean Energy Program

JCP&L urges the Board to reject the RPA's position opposing JCP&L's recovery of lost revenues associated with implementing the Clean Energy Programs. JCP&L argues that the same type of recovery of lost revenues was recently approved by the Board as part of settlement in PSE&G's base rate filing. The Company further notes that the RPA filed no objection to such recovery in the PSE&G base rate proceeding. (Id. at 33-34).

j). Consumer Education

The Company asserts that the Joint Position provides a resolution of JCP&L's CED case that is substantially similar to the resolution of the issue of CED costs in the settlement of PSE&G's base rate proceeding, which was not objected to by the RPA. JCP&L argues that there is no justification for it to receive treatment that is different than that accorded PSE&G on a similar issue. (Id. at 34-35).

k). Transitional Deferred Balances Recovery

Although the Company proposed an interim recovery mechanism for the MTC/BGS deferred balance different from that proposed by the RPA, it accepts the RPA's proposed interim recovery mechanism provided that it is not implemented on a permanent basis. As a result of a letter from the Board's Secretary dated March 25, 2003, the determination of the appropriate permanent recovery mechanism will be deferred. JCP&L reserves its right to address that issue in the appropriate forum. (Id. at 35-36).

2. DOD/FEA

The Department of Defense and other Federal Executive Agencies did not file Exceptions, but did file a Letter Reply to Exceptions. DOD/FEA urges the Board to adopt the Joint Position, and leave unmodified those Cost of Service/Rate Design provisions within the Joint Position as they apply to DOD/FEA. The DOD/FEA compares the rates its facilities pay for energy in New Jersey with the rates paid in Georgia and finds that the rates in New Jersey are nearly double those in Georgia. (DOD/FEA Letter Reply at 3). DOD/FEA argues that, in part, its greater energy costs in New Jersey are driven by a massive disparity in the rate of return paid by customers, like itself, who take service under JCP&L's General Service Transmission Rate Schedule ("GT"). (Id. at 4). The DOD/FEA asserts that in 2002, GT service customers paid an actual class rate of return of 39.78%. (Id.). The DOD/FEA contends that the present GT rate structure is inequitable and constitutes subsidization by the GT class of customers of other classes of the Company's customers. By approving the Cost of Service/Tariff Design proposed in the Joint Position, the Board would help to remedy past inequities and bring about a more efficient rate structure.

3. CO-STEEL

Gerdau Ameristeel, Inc., formerly Co-Steel Sayreville, Inc., filed a Reply to Exceptions in response to the RPA's Exceptions. Co-Steel argues that (1) the objection by the RPA to the MTC treatment accorded Co-Steel in the Joint Position is inappropriate, procedurally improper, and a violation of due process; (2) pursuant to EDECA, the MTC treatment accorded Co-Steel is permissible; (3) the MTC treatment accorded Co-Steel is necessary for the continued economic vitality of the Co-Steel production facility and maintaining employment of its labor force; and (4) the MTC treatment accorded Co-Steel in the Joint Position is consistent with comparable treatment accorded Co-Steel in PSE&G's base rate proceeding. (Gerdau Ameristeel Reply to Exceptions at 2-9).

4. NJCU

The Coalition of New Jersey Commercial Users filed a Statement in Support of the Joint Position. The NJCU believes that the Joint Position offers an overall compromise among the signatory parties that is fair and reasonable and consistent with Board policies. In particular, NJCU argues that the Joint Position addresses a principal concern of Staff by allowing the parties a future proceeding to submit alternative cost-of-service methodologies for the Board's consideration, recognizes the need to eliminate interclass subsidies and reduces the interclass subsidy to residential ratepayers. (NJCU Statement in Support of Initial Decision at 2-6).

5. RPA

The RPA's Reply to Exceptions focused on the Company's Comments in support of the Joint Position.

a) Standard Of Review

The RPA maintains that the Joint Position is flawed. It argues that unlike Staff and the RPA, none of the signatories to the Joint Position participated in all of the issues to the proceeding and that this lack of full participation in the issues of the case fatally undermines the validity of the Joint Position. (RPA Letter Reply to Exceptions at 2-7).

b) Revenue Requirements

i. Rate Base

The RPA contends that, although the DOD/FEA filed testimony on the issue of rate base, only the Company, Staff, and RPA fully addressed the issue of JCP&L's rate base. The RPA asserts that the Joint Position does not take into consideration the positions of Staff and the RPA. (Id. at 8).

ii) Capital Structure and Cost of Capital

Except for the DOD/FEA, none of the signatories to the Joint Position addressed the capital structure/cost of capital, nor did these parties attend the evidentiary hearings pertaining to these issues. The RPA argues that the Joint Position's proposed 10.6% return on equity is contrary to current Board policy. (Id. at 8-9).

iii) Operating Income

Although the Joint Position proposes to reduce the Company's delivery rates by $80 million, only the RPA offered testimony regarding adjustments to JCP&L's operating income. None of the non-Company signatories attended the evidentiary hearings or conducted cross-examination of the witnesses who presented testimony on the various operating income issues. The RPA repeats its arguments that there is no indication of how the parties arrived at the $80 million reduction, and that the inclusion of restructuring costs violates EDECA and general ratemaking principles. (Id. at 9).

c. Depreciation Rates

Again here, the RPA notes that only the Company and the RPA actively participated in the litigation of these issues, and the Joint Position reflects the Company's position and ignores those of Staff and the RPA. (Id. at 10).

d. MTC/BGS Deferred Balance Recovery

Prudence Review of MTC/BGS Deferred Balance: The RPA repeats its criticism of the Joint Position's finding that the entire MTC/BGS deferred balance was reasonably and prudently incurred. The RPA argues that this determination is not supported by credible evidence and that, except for the Company, none of the signatories to the Joint Position filed testimony on the issue and that only the Company, Staff, and RPA appeared at the evidentiary hearing to conduct cross-examination of the Company's witnesses and that only these same parties briefed the issue. The RPA further defends its testimony regarding the price difference between FirstEnergy's, New Jersey and Pennsylvania affiliates as providing a basis to disallow the differential cost. The RPA asserts that the Company was unable to satisfactorily explain the difference in performance between the affiliates and that the performance of the Pennsylvania affiliates was offered as a comparative standard against which JCP&L's performance could be measured. (Id at 4-12).

Recovery/Securitization and Related Carrying Costs: The RPA repeats its argument that the Joint Position proposal on this issue lacks record support. (Id. at 13).

e. SBC Components

The RPA rejects the assertion by the Company that the RPA did not challenge the proposals expressed in the Joint Position regarding the collection of SBC components, full recovery of CEP costs, and the guaranteed recovery of all lost revenues. In addition, the RPA reiterates that the proposal to guarantee the Company full recovery of lost revenues is in violation of a prior Board Order that addressed the claim by utilities for lost revenues.[4] (Id. at 14).

f. Cost Of Service/Rate Design

The RPA asserts that, except for the Company, the nearly exclusive focus of all the signatories to the Joint Position was on issues related to cost of service/rate design. The RPA argues that rather than being a compromise, the Joint Position simply reflects

---

[4] By letter dated July 23, 2003, the RPA responded to JCP&L's Reply to Exceptions on the lost revenue issue. The RPA disputes JCP&L's assertion that the language in the Joint Position is "virtually verbatim" to the language in the recently approved PSE&G case. The language in the Joint Position includes the phrase "and shall receive full and timely recovery thereof through its SBC for the full amount thereof." The RPA notes that this language, with its unequivocal guarantee of recovery is not in the PSE&G Settlement and has not been approved by the Board.

the litigated positions of those parties, whereby each party agreed to minimize its own share of the expenses associated with delivery service to the detriment of the unrepresented parties. (Id. at 14-15).

g. Other Tariff Changes And Tariff Revisions

The RPA criticizes the provision in the Joint Position proposing to increase the Company's cost-based fees. The RPA argues that these increases would disproportionately affect the residential customer which class was not represented in the Joint Position. (Id. at 15).

h. Service Reliability

The RPA rejects the argument by the Company that the issue of the Company's service reliability should be left to a generic proceeding, and contends that the recent outages in the Company's service territory and the re-emergence of the issue of stray voltage requires immediate Board action through the establishment of reliability standards and customer standards with penalties if the established standards are not met.

IV. DISCUSSION AND FINDINGS

A. Introduction

Among state agencies, the Board's decisions are particularly policy-driven. While certain regulatory principles of public utilities remain constant, such as the mandate that public utilities provide safe, adequate and proper service at just and reasonable rates, the role of public utilities in modern life demands policy evolution. Hence, while the Board must enunciate decisions based on the record, the Board's proceedings are properly considered quasi-legislative. E.g., Atlantic City & c., Co. v. Bd. Pub. Utility Commrs., 128 N.J.L. 359 (Supreme Ct. 1942). In keeping with that dichotomy, we issue this order by way of amplification of our Summary Order of August 1, 2003 in these matters.

The record for these consolidated cases is large. There are no less than five separate petitions. Among them is that quintessentially most detailed of utility proceedings, a base rate case. To further complicate this record, the case also includes examination of the aftermath of the single most drastic overhaul of electric utilities in New Jersey regulatory history, the passage of EDECA. To aid us in this process, we lack the benefit of fact-finding and reasoned, objective recommendations of the Administrative Law Judge. Instead, apparently just before the decision was due to be issued, the Company, with various intervenors, presented a document styled as a settlement.[5] Considering this document, the ALJ, following recitation of the procedural history, wrote the following:

> On June 27, the Petitioner, the New Jersey Commercial Users, New Jersey Transit Corporation, Gerdau Ameristeel Sayreville, Inc. (formerly Co-Steel), Independent Energy

[5] Earlier, as noted above, the ALJ had received a settlement among the Company, Staff and the Ratepayer Advocate of the RAC proceeding for which an Initial Decision had been issued.

> Producers of New Jersey and the Department of Defense/other Federal Executive Agencies filed a stipulation of settlement which resolved all issues in the base rate and the deferred balances filings.
>
> The Board Staff and the Ratepayer Advocate were not signatory to the stipulation but have been duly served by electronic mail with a copy of the settlement. In view of the time constraints imposed by the BPU and the August 1, 2003 deadline for the removal of the caps, any objections to this settlement should be submitted to the Board as exceptions.
>
> After a thorough review of the Settlement, I **FIND** that the stipulation of settlement represents a fair and reasonable resolution of all the issues in this matter. I further **FIND**:
>
> 1. The parties to the above-mentioned settlements have voluntarily agreed to their terms as evidence by their signatures or the signatures of their representatives.
>
> 2. The settlements fully dispose of all issues in controversy and are consistent with the law.
>
> Therefore, I **CONCLUDE** that the agreements meet the requirements of N.J.A.C. 1:1-19.1 and that the settlements should be approved. Accordingly, it is **ORDERED** that the settlement terms are approved, and it is **FURTHER ORDERED** that the proceedings in this matter be concluded.
>
> [Initial Decision at 5-6]

Thus, the Board was presented with a novel situation. In a complex series of cases involving a major electric utility, in the absence of recommended fact-finding from the OAL, the Company with some intervenors, but neither our Staff nor the Ratepayer Advocate, filed a settlement.

The Board has always been guided by the salutary public policy in favor of settlements. Indeed, the Board has been pragmatic in its recognition of settlement as a sound conclusion of litigation. Notably, the Appellate Division approved the Board's adoption of a non-unanimous settlement including most of the active parties. I/M/O the Petition of Public Service Electric and Gas Co., 304 N.J. Super. 247 (App. Div.) certif. den. 152 N.J. 12 (1997). In so affirming the Board's approach, the Court emphasized the essential soundness of a settlement by the parties "in the best position to determine how to resolve a contested matter in a way which is least disadvantageous to everyone." (Id. at 266.) The concept that the "active parties participate[d] in negotiating the settlement," id. at 270, informed the Court's acceptance of a non-unanimous settlement. There, of course, both Staff and the Ratepayer Advocate were lively participants and signators to the settlement.[6] Despite general support of settlements, courts have never abandoned their obligation to ensure overall fairness of settlements and protection of all parties. E.g., Eichenholtz v. Brennan, 52 F.3d, 478 (3d Cir. 1998).

In contrast, here, the purported settlement was solely the creature of the Company and New Jersey Commercial Users, New Jersey Transit Corporation, Gerdau Ameristeel Sayreville, Inc. (formerly Co-Steel), Independent Energy Producers of New Jersey and the Department of Defense/other Federal Executive Agencies. Although the document's provenance is hazy, certainly neither Staff nor the Ratepayer Advocate participated in such negotiations which gave rise to the agreement nor did they sign. Instead, both filed exceptions thereto.

Analysis of this document must begin with the observation that none of the signator intervenors could be characterized as fully active participants in the entire proceedings. As large energy users, these parties appropriately participated to the degree they deemed necessary to support their parochial interests. Apart from the Company, the interests of which need go unremarked, the breadth of interests which are necessary to settlement were absent. Thus, the happy results for the Company are unsurprising: 100% of recovery of deferred balance, return on equity of 10.6% and generosity with respect to revenue requirements. For the large customers, the result was agreeable tariff design. In other words, the Company essentially reached a settlement with itself.[7] Accordingly, this settlement and the Initial Decision adopting it are **HEREBY REJECTED** except insofar as particular tariff design components are adopted as will be set forth below.

Related to this rejection is NJCU's motion before the OAL for partial summary disposition on the issue of cost of service methodology to avoid conflict between this case and the parallel Public Service Electric and Gas case. While NJCU was a party to the settlement approved by the ALJ in the Initial Decision to conclude the OAL proceedings, our rejection of that decision theoretically revives the motion. The issue is moot because of the resolutions of both proceedings. Further, NJCU both failed to provide factual support in the record in support of the motion and to know that it is entitled to judgment as a matter of law. Brill v. Guardian Life Ins. Co., 142 N.J. 520 (1995). Accordingly, the motion is **HEREBY DENIED**.

As set forth in the Summary Order, we generally adopt the recommendations of Staff which sometimes were congruent to those of the Ratepayer Advocate. Because the positions of the parties were so critical to our analysis of the issues in these proceedings, we have generally set them forth in some detail following our discussion and analysis. The format varies somewhat between the rate case and its traditional issues and the uncharted territory of the deferred balances component. To this extent,

[6] Of course, New Jersey has never endorsed uncritical acceptance of a utility's records. E.g., Public Service CoordinatedTrans. v. State, 5 N.J. 196, 218 (1950).

[7] To the extent JCP&L would attempt to articulate some sort of fungibility argument generally with respect to New Jersey electric utilities and specifically with respect to settlements, that effort is misguided. As to the former, no comment is necessary. As to the latter, we note that while neither Staff nor the Ratepayer Advocate signed the settlement in the parallel proceeding for Public Service Electric and Gas Co., both Staff and the Ratepayer Advocate actively participated in the negotiations.

we do not do so under every issue and subissue which do not follow precisely this order, we **HEREBY** **ADOPT** the recommendations of Staff as our findings for the following issues as supplemented where indicated by the recommendations of the Ratepayer Advocate:

Rate Case

- Cash Working Capital
- Consolidated Taxes (with Ratepayer Advocate)
- Customer Growth
- Clean Energy - Lost Revenues (with Ratepayer Advocate)
- Charitable Contributions (with Ratepayer Advocate)
- SAP/Amortization of Expenses (with Ratepayer Advocate)
- Rate Case Expenses (with Ratepayer Advocate)
- Production-Related Amortization (with Ratepayer Advocate)
- Restructuring Transition Costs
- Incentive Compensation
- Miscellaneous
- Interest Synchronization
- Gross Receipts and Franchise Tax (with Ratepayer Advocate)
- Performance Standards
- Rate of Return (Staff as modified herein)
- Capital Structure

Deferred Balance Case

- With Auditors, Staff and Ratepayer Advocate as modified herein

B. Cost of Capital

JCP&L

JCP&L proposes a rate of return of 12.0% on its common equity capital, provided that its requested rate relief and the securitization of its deferred balances are approved. In reaching its requested rate of return, JCP&L balanced various considerations including (1) fairness to the ratepayer; (2) ability to attract capital on reasonable terms; (3) maintenance of its financial integrity, and (4) comparability of its return to the returns offered on other comparable risk investments. JCP&L used three market-based methodologies to derive its estimated cost of capital: (1) the Capital Asset Pricing Model ("CAPM") Risk Premium (JC-6; P113 at 23-49); (2) the Empirical Risk Premium, and (3) several Discounted Cash Flow ("DCF") methodologies. More specifically, in arriving at a range of estimates reflecting the various applications of the above methodologies, JCP&L performed two CAPM analyses, both a simple CAPM and an empirical approximation of the CAPM; a historical risk premium analysis for the electric utility industry, and the natural gas distribution utility industry, and a study of the risk premiums actually allowed in the electric utility industry; and a DCF analysis on two surrogates for JCP&L's electric distribution business, including a group of comparable natural gas distribution utilities and a group of combination gas and electric utilities. (JC at 14; PIB at 28-39). JCP&L's use of three market-based methodologies is due to the inability of one individual method to provide the necessary level of precision for determining a fair rate of return. JCP&L asserts that, when viewed in conjunction with each other, each method serves as a check and provides a useful basis on which to make an informed judgment. Based on the results of the various analyses it conducted, JCP&L arrived at a range of 10.8% to 13.2% as the appropriate ROE. (JC-6 at 41; PIB at 24-41).

The range of ROE estimates obtained through application of the various methodologies averaged to about 11.75%, which JCP&L asserts reflects the risk of the average distribution company. JCP&L argues that because its investment risk slightly exceeds those of the group, the expected equity return has a downward bias. JCP&L estimates this bias at 25 basis points, which when applied to its average estimated ROE brings its requested ROE to 12.0%. (JC-6 at 4; PIB at 25-26).

RPA

The RPA recommends a ROE of 9.5%, plus an additional 35 basis points to reflect the financial risks which the RPA considers as inherent in FirstEnergy's highly leveraged capital structure. (RAIB at 12-18). The RPA's proposed recommendation is based on two variations of the DCF methodology i.e., the constant growth model and a multiple period model, and a risk premium analysis based on the CAPM. (RAIB 14-18).

The RPA argues that its proper use of the DCF and CAPM produces an appropriate range of ROE estimates as contrasted with the improper application of the two methodologies by the Company. The RPA further contends that JCP&L's reliance on the Historical Risk Premium and Allowed Risk Premium methodologies is misplaced due to the inherent conceptual and empirical flaws found in both methodologies. Specifically, the RPA faults the Company's analysis due to (1) improper use of the constant growth DCF model; (2) improper use of the CAPM; (3) overstating the Risk Premium; (4) misuse of data in the empirical CAPM analysis; (5) invalid Risk Premium methodologies, and (5) an unsupported flotation cost allowance. (RAIB at 18-24).

The RPA's analysis produced a range of estimated ROE from 9.0% to 10.0%, with the CAPM results indicating a cost of equity at the lower range and the DCF analysis producing results at the higher range of the estimates. The RPA's recommended 9.5% ROE reflects the midpoint of the ROE estimates. To this, the RPA adds an additional 35 basis points to account for the unusually low equity ratio of its recommended consolidated capital structure discussed above. (RAIB at 12-18).

Staff

Staff criticizes both JCP&L and the RPA for using traditional rate of return on equity methodologies without acknowledging the fundamental structural changes that Staff asserts are key to understanding the prospective circumstances under which JCP&L will be operating. Staff asserts that the proxy groups used by both JCP&L and the RPA to estimate the ROE are not sufficiently comparable to JCP&L to provide a valid surrogate for its risk-return requirements. Staff asserts that a comparable proxy group should be based upon (1) comparable companies in the same industry; (2) companies of comparable credit quality, and (3) companies having no significant investments in non-regulated higher risk ventures that could distort, i.e., increase, the estimate of the average return on equity of the sample companies. (SIB at 17-18).

Staff asserts that JCP&L's analysis does not capture the significant reduction in the risks it faces as a result of restructuring, divestiture of its generating assets, and the shifting of generation risks to consumers via the auction. Staff asserts that JCP&L's use of non-comparable proxy groups leads to estimates that do not reflect its new risk profile. (SIB at 22-32). Staff reviewed JCP&L's results for the various iterations of the CAPM, Risk Premium and DCF models, and argues that the natural gas and the combination gas and electric industries are not comparable to JCP&L, and that the electric industry estimates include the major risk factor of electric generation which is not present in JCP&L's risk profile. (SIB at 23-28). Staff reasons that JCP&L's customers should pay a return on equity that reflects: (1) only the risk of a "wires" company; (2) the absence, for now, of head-to-head retail competition; (3) the removal of any risks associated with non-regulated investments of FirstEnergy and its subsidiaries, and (4) the removal of risks associated with the construction, operation and ownership of nuclear and fossil electric generation.

Similarly, Staff criticizes the RPA for using in its analysis the same sample companies selected by JCP&L. (SIB at 30-31). Staff believes that the RPA did not demonstrate the comparability of the companies used in its analysis in terms of industry, business model, credit quality and risk class, based on JCP&L's characteristics, not FirstEnergy's. Use of this proxy group produces a result that is not appropriate to the lower risk JCP&L. (Id.).

Staff also criticizes the RPA's analysis for failing to explain how it translated a market cost of equity for the various parent holding companies into a cost of equity for the regulated subsidiary JCP&L. Staff contends that each of the sample companies has some elements of non-regulated businesses, electric generation, and other high-risk activities. Staff argues that it is essential that the effects of these higher risk activities be removed from the data; otherwise, the proposed cost of equity is more appropriately applied to the parent, FirstEnergy. (SIB at 31).

In making its recommendation for an appropriate ROE for JCP&L, Staff noted the RPA's recommended 9.5%, and the Company's 12%. Staff observed that two recent New Jersey gas base rate cases settled at 10% for the riskier gas industry,[8] and reasoned that it would be difficult to support a recommendation above 10%. Staff concluded that in light of the evolution of JCP&L from a traditional electric utility to a wires only business and corresponding reduction in risk, 9.75% represents an appropriate cost of equity. (SIB at 31-32).

---

[8] I/M/O the Petition of NUI Utilities, Inc., d/b/a Elizabethtown Gas Company for Approval of Increased Base Tariff Rates and Charges for Gas Service and Other Tariff Revisions, BPU Dkt. No. GR02040245, (November 22, 2002); I/M/O the Petition Of Public Service Electric & Gas Co. for Authority To Revise Its Gas Property Depreciation Rates & I/M/O the Petition Of PSE&G For Approval of an Increase in Gas Rates & for Changes in the Tariff for Gas Service, B.P.U.N.J. NO. 12, Gas Pursuant to N.J.S.A. 48:2-21 and N.J.S.A. 48:2-21.1, BPU Dkt. Nos. GR01050297 and GR01050328, (January 9, 2002).

C. **Capital Structure**

JCP&L

Consistent with the Board's October 9, 2001 Order approving the merger of JCP&L's then parent company, GPU Inc., and FirstEnergy, Inc. ("FirstEnergy") ("Merger Order"), JCP&L filed two alternative capital structures; a consolidated capital structure based on FirstEnergy's capital structure and a "stand-alone" JCP&L capital structure. (Exhibit JC-5, Schedule TCN-1). JCP&L supported the use of the stand-alone capital structure, provided that two adjustments were made to its actual capital structure. The first adjustment eliminates the purchase accounting adjustments associated with the capitalization portion of the JCP&L balance sheet. The second adjustment removes the effects of the $300 million deferred balance write-off as required by in the Merger Order. (Id. at 8-9) JCP&L asserts that the capital structure resulting from these adjustments is fair to its customers and to the Company and is vital to maintaining its access to the capital markets.

JCP&L's proposed capital structure includes 57.22% common equity, 4.95% preferred stock and securities and 37.83% short-term debt. (JC-5, Schedule TCN-6).

JCP&L rejects the use of a consolidated capital structure for ratemaking purposes. It argues that using a consolidated capital structure would not produce the savings envisioned by the RPA, because only $2.2 billion of First Energy's new debt was used to finance the $4.8 billion purchase price of the GPU merger and more than half of the purchase price or $2.6 billion was paid in the form of new common equity stock issued by FirstEnergy to GPU stockholders. (JCP&L Initial Brief at 19).[9]

JCP&L asserts that virtually every major public utility in the State is structured as a local operating subsidiary of a larger parent holding company, and that the Board has not substituted the parent holding company's capital structure for that of the operating utility for ratemaking purposes. (PIB at 21). In addition, JCP&L observes that unlike in the instant proceeding, the RPA, which is a party to the PSE&G rate proceeding, did not in that case recommend using a consolidated capital structure.

RPA

The RPA recommends use of FirstEnergy's consolidated capital structure for ratemaking purposes. It opposes the use of a stand-alone capital structure, and rejects the two adjustments proposed by JCP&L. The RPA argues that a stand-alone capital structure deprives the ratepayers of the benefits of the lower capital costs associated with the $4.5 billion in long-term debt issued by FirstEnergy to finance the merger. The RPA asserts that the use of a consolidated capital structure is consistent with the Board's recent telecommunications decision, wherein, the Board adopted the RPA's proposed

---

[9] Petitioner, JCP&L's Initial Brief will hereinafter be referred to as "PIB". The Ratepayer Advocate's Initial Brief will be referred to as "RAIB" and the Staff's Initial Brief will be referred to as "SIB".

consolidated capital structure[10]. (RAIB at 7). In addition, the RPA asserts that a consolidated capital structure is less susceptible to manipulation, in that FirstEnergy's capital structure resulted from arms-length transactions in the capital markets, whereas JCP&L's capital structure is dictated by the corporate parent. (RAIB at 9). Finally, the RPA argues that using a consolidated capital structure is consistent with the practices of credit reporting agencies, which, the RPA contends, rarely view regulated subsidiaries on a stand-alone basis. (RAIB at 10).

The RPA's proposed capital structure is significantly different than that of the Company and consists of 37.20% common equity, 5.40% preferred stock and 57.40% long-term debt. (R-41, BLC-1).

Staff

As set forth in its brief, Staff asserts that JCP&L should be viewed as a stand-alone company, whereby only the risks of JCP&L are relevant when estimating its cost of equity. Staff asserts that the risks faced by FirstEnergy and its major subsidiaries should not be reflected in the ratemaking process. (SIB at 15-17). In addition, the credit quality of JCP&L, as measured by debt ratings from Moody's, Fitch, and Standard & Poor's, should also be determined on a stand-alone basis. Staff asserts that if JCP&L's credit were viewed as independent of FirstEnergy, JCP&L would be better insulated from the harmful consequences that might result from downgrades of the credit quality of FirstEnergy or its unregulated subsidiaries. Staff asserts that this insulation is in fact required by the Board's Merger Order. (SIB at 17).

As for JCP&L's proposed changes to its capital structure, Staff asserts that in light of the reduced operating risks facing JCP&L and the very high coverages implied therein, adoption of JCP&L's recommendations would impose excessive costs on customers that are beyond those needed to retain investment grade ratings.

Staff recommends adoption of a less leveraged capital structure than that recommended by the RPA. Staff recommends a capital structure consisting of 46.00% common equity, 5.66% tax-deductible preferred ("MIPS") 0.57% preferred stock and 47.77% long-term debt. (SIB at 20, Table 1).

Staff argues that its proposed capital structure should provide, along with supportive regulation, a level of financial integrity sufficient to ensure an investment grade rating for JCP&L. Staff observes that its recommended capital structure is sufficient given the limited external capital requirements facing JCP&L, and that a 46% equity ratio is just about the same level allowed in JCP&L's last rate case when it had significantly higher risks, including full generation responsibilities. (SIB at 20-21).

Board Discussion and Analysis

It is well established that a public utility is entitled to such rates as will permit it to earn a return on the value of the property employed for the convenience of the public, equal to

---

[10] I/M/O the Board's Review of Unbundled Network Elements Rates, Terms and Conditions of Bell-Atlantic-New Jersey, Inc., BPU Docket No. TO00060356 (March 6, 2002)

that generally being made at the same time and in the same general part of the country on investments in other business undertakings attended by corresponding risks and uncertainties. Bluefield Water Works & Improvement Company v. Public Service Commission of West Virginia, 262 U.S. 679, 692 (1923). With broad discretion the Board must determine what, in a particular situation, is a just and reasonable return for a public utility. Atlantic City Sewerage Co. v. Board of Public Utility Com'rs, 128 N.J.L. 359 (1942), aff'd 129 N.J.L. 401 (E&A 1943). Public utility rates are valid so long as they enable the utility to operate successfully, maintain its financial integrity, attract capital and compensate its investors for the risk assumed. FPC v. Hope Natural Gas Co., 320 U.S. 591, 605 (1944). In other words, if the total effect of the rate order is not unreasonable, judicial inquiry ends. Thus, a cost of equity figure is appropriate so long as it is "within the range of reasonableness, the zone between the lowest rate not confiscatory and the highest rate fair to the public." In re N.J. Power & Light Co., 9 N.J. 498, 535 (1952).

There is one further consideration with respect to rate of return. While repeating the fundamental principle that public utilities are to be granted just and reasonable rates for safe, adequate and proper service should not be a restatement of the obvious, apparently the ancient link between good service and rates is not as clear as it should be to all segments of the regulated community. This nexus is well settled both in New Jersey, e.g., I/M/O Petition of Valley Road Sewerage Co., 154 N.J. 224 (1998), and beyond, e.g., US West Communications, Inc. v. Washington Utilities and Transportation Comm'n., 134 Wash. 2d 74, 949 P.2d 1337 (1998).

The Board has issued three summary orders for PSE&G, RECO, and JCP&L. In each of those Orders, the Board made Findings with regard to the traditional rate case issue of Cost of Capital. The sub-issues related to the appropriate capital structure and the component costs for common equity and long-term debt. The records developed on these issues in each case are extensive and have provided the Board with sufficient information upon which the Board has relied in issuing FINAL DECISIONS AND ORDERS for Rockland and PSE&G.

The Board believes that the regulatory principles developed by the Staff and adopted by the Board in the RECO and PSE&G Orders should also be adhered to in this Order as the basis for reaching a decision on the appropriate capital structure and cost of capital to be used by JCP&L in setting its permanent rates. Most notably, the Board believes that the overall risks facing the electric utility distribution companies in New Jersey have decreased as a result of the various provisions of EDECA. Foremost is the Basic Generation Service Auction process that the Board has adopted for the procurement of power for the electric companies in New Jersey. The BGS process eliminates the risks associated with the companies' planning, construction and operation of generation facilities. The resulting "wires only" distribution companies should therefore require a lower cost of capital that ratepayers are required to support in their retail rates. Additionally, the companies have the ability to request the recovery of stranded costs and deferred balances either through traditional amortization in rates or where approved by the Board through "securitization." These major rate making benefits materially contribute to the reduction of risk faced by the electric utilities in New Jersey.

During the course of litigating and deliberating on this case, the Board was compelled to deal with a number of operating problems directly attributable to JCP&L's failure to appropriately maintain system reliability. These recurring problems brought into sharp focus the potentially serious long-term negative impacts on their customers, the economy of their service territory, and on the confidence of ratepayers in the Board's ability to effectively regulate JCP&L. The Board cannot ignore these recurring reliability problems and determined to take immediate action to construct an interim remedial regulatory incentive mechanism.

The Board will use the allowed return on equity as the most direct and powerful signal that they can send to the company to improve their system reliability and do it as soon as practicable. The Board **ORDERS** that the Company's return on equity be reduced from the 9.75% allowed above to 9.50%, a reduction of 25 basis points, until such time as the Company provides sufficient evidence to the Board that they have made the necessary improvements required to maintain system reliability. The Company will be provided a full opportunity to make their case and reestablish 9.75% as their allowed return on equity. However, as noted in our Summary Order, if the Company does not meet these requirements ,…"the Board reserves its rights to take further appropriate actions, including, but not limited to, reducing the return on equity to as low as 9.25% from the date of this Order." The capital structure and the calculation of the cost of capital are shown in Exhibit appended to this Order.

Historically the allowed return on equity is one key measure used by the financial community in estimating the opportunity for the Company to earn a reasonable return on its regulatory rate base. Hopefully the prominence of this financial measure and the statutory mandate to provide safe, adequate and proper service will combine to provide the compelling incentives for the Company to restore system reliability.

After reviewing the record evidence on cost of capital and capital structure, the Board **ADOPTS** the analysis and resulting recommendations of Staff and **FINDS** that the appropriate return on equity for JCP&L should be set at 9.50% and JCP&L's overall cost of capital is 8.38%.

D. Cash Working Capital ("CWC") and Lead/Lag

Both JCP&L and the RPA utilized the lead/lag study method to determine JCP&L's cash working capital requirements. Staff agreed with JCP&L and the RPA that the lead/lag method is the most appropriate to use to determine the Company's revenue requirement. (SIB at 35). The cash working capital issues include 1) depreciation, 2) amortization expenses, 3) regulatory debits and credits, 4) deferred taxes, 5) tax credits, 6) JCP&L's common equity return and 7) JCP&L's payment of dividends on preferred stock and interest on long-term debt.

JCP&L

JCP&L included these items in its lead/lag study with a zero lag. (JC-11 Rebuttal at 5-7). JCP&L asserts that referring to these items as "non-cash" is misleading because it suggests that there is no cash outlay by investors. JCP&L asserts that the depreciation expense constitutes the required return of capital previously invested in plant and equipment which constitutes a major portion of its rate base, and which is reduced by the accumulated depreciation. Because investors must wait to receive the return-of-capital cash payment of the depreciation expense in the form of utility revenues, there must be a CWC requirement to the extent of the revenue lag. (Ibid.).

JCP&L contends that deferred taxes are initially created to reflect timing differences between book depreciation and the tax depreciation expense on cash invested in utility plant, which are deducted from rate base. JCP&L argues that the level of deferred income taxes reflected on the income statement must be included in the CWC study with a zero lag in order to compensate investors for the lag in the recovery of current revenue related to that expense. (JC-11 Rebuttal at 6).

RPA

The RPA argues that these items are non-cash expenses and their inclusion in the lead-lag analysis overstates JCP&L's cash working capital requirement. (R-38 at 9-10). The RPA asserts that for these costs, the cash transaction has already occurred and that neither the deferred charges nor the other non-cash expenses requires a current cash outlay. Because no periodic cash outlay is required, no investment in working capital is required. This is especially true with respect to deferred taxes, which have been collected from ratepayers without being paid by the utility to the Internal Revenue Service. (Ibid.).

Staff

Staff recommends inclusion of these items in the lead/lag study with a zero lag as proposed by JCP&L with the exception of deferred taxes and tax credits. (SIB at 36). Staff recommends exclusion of deferred taxes and tax credits from the calculation of working capital as proposed by the RPA. Staff argues that there is a key distinction between depreciation and deferred taxes and asserts that although JCP&L's investors financed the construction of utility plant leading to the depreciation expense, deferred taxes arise more from timing differences associated with the tax code than an outlay of investor capital. Staff supports its analysis by referencing several prior Board decisions.[11] (SIB at 36-37).

Board Discussion and Analysis

In I/M/O Public Service Electric and Gas Company for an Increase in Rates, BPU Docket No. ER85121163, dated April 6, 1987, the Board adopted that portion of the ALJ's recommendation regarding the assignment of a zero lag in the lead/lag study to the Company's depreciation expense. The Board concurs with the ALJ's findings on this issue, specifically, where the ALJ found:

[11] I/M/O Public Service Electric and Gas Company for an Increase in Rates, BPU Docket No. ER85121163, (April 6, 1987); I/M/O Middlesex Water Company for Approval of an Increase in its Rates for Water Service and Other Tariff Changes, BPU Docket No. WR00060362, (June 6, 2001); I/M/O Public Service Electric & Gas Company for an Increase in Rates, BPU Docket No. ER85121163, (April 6, 1987); I/M/O Elizabethtown Gas Company for Approval of Increased Base Tariff Rates and Charges for Gas Service and Other Tariff Revisions, BPU Docket No. GR88121321, (February 1, 1990).

> Staff advances the position that the investors should be compensated for the revenue lag in the recovery of depreciation expense and the amortization of owned nuclear fuel. This is true since the Company's investors have financed the construction of plant and the purchase of nuclear fuel.
>
> The Company should be allowed to earn a return on these funds until the dollars are actually returned to the investor. The return on the investment is accomplished over the period of time the investment benefits ratepayers through their payment of annual depreciation and the amortization expense. Ratepayers have been overcompensated. At the time the items are reflected on the books, the cash associated with those items has not been returned to the investors. Accordingly, the only way to adjust for this factor is to assign a zero lag in the lead/lag study to the depreciation expense and the amortization of owned nuclear fuel. This appropriately reflects the fact that the collection of revenue lags behind the provision of service by 42.2 days.
>
> [Initial Decision in I/M/O Public Service Electric and Gas Company for an Increase in Rates, BPU Docket No. ER85121163 at 33]

This finding was also upheld in the Board's Order in I/M/O Middlesex Water Company for approval of an Increase in its Rates for Water Service and Other Tariff Changes, BPU Docket No. WR00060362, dated June 6, 2001, where the Board stated, "the Board ADOPTS the position of the Staff and the Company, consistent with prior Board findings, that depreciation should be included in the lead/lag study and assigned zero days." Id. at 17.

As to the treatment of deferred income taxes in the lead/lag study, in I/M/O Public Service Electric & Gas Company for an Increase in Rates, BPU Docket No. ER85121163, dated April 6, 1987, the Board adopted that portion of the ALJ's recommendation on this issue where the ALJ found:

> I FIND that deferred taxes should be excluded from the lead/lag study because they did not, at any point in time, require investor-supplied capital. It would be unreasonable and inappropriate to force ratepayers to pay a return on funds not supplied by investors.
>
> [Initial Decision in I/M/O Public Service Electric & Gas Company for an Increase in Rates, BPU Docket No. ER85121163 at 35.]

The Board affirmed this policy in I/M/O Elizabethtown Gas Company for Approval of Increased Base Tariff Rates and Charges for Gas Service and Other Tariff Revisions, BPU Docket No. GR88121321, Final Order dated February 1, 1990, where the Board found:

> The ALJ was persuaded by Staff's argument as to the proper ratemaking treatment for deferred taxes. The ALJ recommended that deferred taxes be deducted from operating revenues in the working capital allowance for purposes of this proceeding. The Board FINDS the ALJ's determination on deferred taxes to be reasonable and consistent with Board policy. Therefore, the Board ADOPTS the ALJ's conclusion on this issue.
>
> [Id. at 7].

The Board **ADOPTS** Staff's recommendation that these items be included in the lead/lag study and assigned a zero lag as proposed by the Company with the exception of deferred taxes and tax credits. The Board further **ADOPTS** Staff's recommendation that deferred taxes and tax credits be excluded from the calculation of working capital as proposed by the RPA. The Board **FINDS** that there is a key distinction between depreciation and deferred taxes. The Company's investors have financed the construction of plant, which led to the depreciation expense. However, the deferred taxes more succinctly arise from timing differences associated with the tax code than an outlay of investor capital. This finding is supported by prior Board decisions in this area.

E. Common Equity Return, Payment of Dividends on Preferred Stock and Interest on Long-term Debt

JCP&L

In its lead/lag study, JCP&L included the return on invested capital, with a zero lag. JCP&L asserts that this is consistent with prior Board rulings and argues that operating income is the property of the investor immediately upon the rendition of service. To exclude the revenue lag relating to the recovery of the return on equity would wrongly disallow a portion of the cost of service. (JC-11 Rebuttal at 4). JCP&L also contends that long-term debt interest and preferred stock dividends are part of investor returns to be paid from operating income. (Id. at 7-8).

RPA

The RPA disagrees with JCP&L's inclusion of the common equity return in its lag study with a zero lag, arguing that this would be tantamount to JCP&L compensating its stockholders on a daily basis. The RPA notes that compensation is received by stockholders in two forms: through quarterly dividend payments, and through capital appreciation upon the sale of the stock. (R-38 at 10-11). The RPA argues that to measure the actual delay in the cash outlay by the utility to stockholders, one should refer to the quarterly dividend payments that are being paid, and not simply assume a zero lag. Here, however, because there is no contractual requirement for FirstEnergy to pay fixed quarterly dividends to its stockholders the common equity return should not be included in the cash working capital measurement. (Ibid.)

In addition, the RPA argues that JCP&L should not have lumped long-term debt interest and preferred stock dividends with the common equity return and applied a zero-day lag. (R-38 at 11). According to the RPA, there are contractual requirements associated with debt interest and preferred stock dividends that obligate JCP&L to make specified payments on certain dates. In this respect, debt interest and preferred dividend elements of JCP&L's return more closely resemble its other cash operating expenses. Further, where these items fall on the income statement is irrelevant; the Company has had the use of those funds until it pays the investor or stockholder and that time period should be reflected in the lead-lag study. (5T:104-6 to 105-4). The payment leads for long-term debt interest and preferred stock dividends should be separately recognized in the lead-lag calculation. The RPA calculates a 91.25-day expense lead for debt interest, which is paid semi-annually, and a 45.63-day expense lead for preferred stock dividends, which are paid quarterly, and includes these in its lead-lag calculation. (Ibid.; R-38, 11).

Staff

Staff recommends, consistent with prior Board decisions,[12] inclusion of the return on invested capital in the lead/lag study and assigning a zero lag as proposed by the Company. Staff believes that investors are entitled to earn a return as service is rendered through the cash working capital requirement for the use of their funds while they are retained in the business. (SIB at 41-42).

Board Discussion and Analysis

The Board **ADOPTS** Staff's recommendation that the return on invested capital be included in the lead/lag study and be assigned a zero lag as proposed by the Company. The Board **FINDS** that investors are entitled to earn a return as service is rendered, that is, daily. Stockholders are entitled to compensation through the cash working capital requirement for the use of their funds while they are retained in the business. This finding is consistent with Board policy regarding this issue. Specifically, in I/M/O New Jersey Natural Gas Company for Approval of Increased Base Tariff Rates and Charges for Gas Service and Other Tariff Revisions, BPU Docket No. GR89030335J, Final Order dated July 17, 1990, the Board noted:

> The ALJ accepted the Company and Staff's position as to the proper ratemaking treatment to be accorded return on invested capital. The ALJ was persuaded that ample Board precedent supports the position that the return on invested capital should be included in the lead/lag study with a zero lag. We agree and have held that the return on invested capital should be assigned a zero lag.
>
> [Id. at 15].

[12] I/M/O New Jersey Natural Gas Company for Approval of Increased Base Tariff Rates and Charges for Gas Service and Other Tariff Revisions, BPU Docket No. GR89030335J (July 17, 1990); and I/M/O Middlesex Water Company for Approval of an Increase in its Rates for Water Service and Other Tariff Changes, BPU Docket No. WR00060362, (June 6, 2001).

It is also consistent with the Board's decision in I/M/O Middlesex Water Company for Approval of an Increase in its Rates for Water Service and Other Tariff Changes, BPU Docket No. WR00060362, dated June 6, 2001 in which the Board stated: "The Board REJECTS the RPA's position that the return on common equity should be removed from the lead/lag study." Id. at 17.

F. Consolidated Tax Adjustment

JCP&L

JCP&L's former parent company, GPU, Inc., included JCP&L in its consolidated federal income tax filing along with GPU's other subsidiaries. (JC-4, Schedule RFP-2; R-38). As a result of making a consolidated tax filing, GPU as a whole paid less federal income taxes than it would have if each subsidiary filed separately, thus producing a tax savings. In this proceeding, JCP&L proposes that none of the consolidated tax savings flow to JCP&L's customers. Instead, these tax saving would all flow to the loss affiliates. Essentially, JCP&L proposes that its rates be set in this proceeding as though JCP&L paid its taxes on a stand-alone basis. The Company argues that there is no basis for any prospective consolidated tax savings adjustment because the unregulated affiliates had a cumulative positive taxable income during the period in question and the tax savings could have been produced by offsetting the tax losses by the positive income of the unregulated companies. JCP&L argues that the loss affiliates would have operated differently had the benefits of consolidation not flowed to the benefit of non-utility operations. (PIB at 58-61; 5T:80-13 to 82-2).

Staff / RPA

Staff observes that if each of the affiliates paid the amount that their tax liability would be on a stand-alone basis, they would be paying more for taxes than would actually be paid by GPU to the IRS. (SIB at 43). The Staff believes that, consistent with law and long-standing Board policy[13], the tax savings should be shared with JCP&L's customers, because JCP&L contributed to the tax savings with its positive taxable income, which was provided by ratepayers. (SIB at 43-44). Staff asserts that the Company's argument that the tax savings could have been produced by offsetting the tax losses by the positive income of only unregulated companies is as arbitrary and unfair as it would be to say that the losses could have been offset by the positive income of only regulated companies and, therefore, all the savings should be allocated to regulated companies only. (SIB at 47).

[13] In re Lambertville, 153 N.J. Super. 24, 28 (App. Div. 1977), reversed in part, 79 N.J. 449 (1979); I/M/O the Petition of Atlantic City Electric Company for Approval of Amendments to its Tariff to Provide for an Increase in Rates and Charges for Electric Service, Phase II, BPU Docket No. ER90091090J (October 20, 1992); I/M/O the Petition of Jersey Central Power and Light Company For Approval of Increased Base Tariff Rates and Charges for Electric Service and Other Tariff Revisions, BPU Docket No. ER91121820J (June 15, 1993).

Both Staff and RPA recommend that a “rate base” methodology be used to calculate consolidated tax savings in this proceeding. (SIB at 46-47). Staff notes that the IRS has found that the rate base method does not violate IRS normalization requirements. The rate base methodologies proposed by the Staff and RPA differ slightly in that the RPA calculates the savings on a yearly basis, while Staff looks at the data over the entire period. Staff believes that its proposed methodology is appropriate, because it was previously approved by the Board and allows for the fact that a company could utilize its net operating loss on a stand-alone-basis under the carry back and carry forward provisions of the Internal Revenue Code. Staff recommends that the Board order a consolidated tax savings adjustment in the amount of $36.9 million.

Board Discussion and Analysis

As a result of making a consolidated tax filing during the years 1991-1999, GPU, JCP&L’s parent company during that time period, as a whole paid less federal income taxes than it would have if each subsidiary filed separately, thus producing a tax savings. The law and Board policy are well-settled that consolidated tax savings are to be shared with customers. I/M/O the Petition of Atlantic City Electric Company for Approval of Amendments to its Tariff to Provide for an Increase in Rates and Charges for Electric Service, Phase II, Docket No. ER90091090J (Order dated October 20, 1992) (“1992 Atlantic Electric Order”); I/M/O the Petition of Jersey Central Power and Light Company for Approval of Increased Base Tariff Rates and Charges for Electric Service and Other Tariff Revisions, Docket No. ER91121820J (Order dated June 15, 1993) (“1993 JCP&L Order”). Moreover, the New Jersey courts have confirmed that the BPU has “the power and the function to take into consideration the tax savings flowing from the filing of a consolidated return and determining what proportion of the consolidated tax is reasonably attributable to [the utility].” Lambertville Water Company v. New Jersey Bd. Of Public Utility Com’rs, 153 N.J. Super. 24, 28 (App. Div. 1977), reversed on other grounds, 79 N.J. 449 (1979), (citing FPC v. United Gas Pipe Line Co., 386 U.S. 237, 87 S.Ct. 1003, 18 L.Ed.2d 18 (1967).

In the Board’s 1993 JCP&L Order, supra, the Board clearly explained that:

> The Board believes that it is appropriate to reflect a consolidated tax savings adjustment where, as here, there has been a tax savings as a result of the filing of a consolidated tax return. Income from utility operations provides the ability to produce tax savings for the entire GPU system because utility income is offset by the annual losses of the other subsidiaries. Therefore, the ratepayers who produce the income that provides the tax benefits should share in those benefits. The Appellate Division has repeatedly affirmed the Board’s policy of requiring utility rates to reflect consolidated tax savings and the IRS has acknowledged that consolidated tax adjustments can be made and there are no regulations which prohibit such an adjustment. The issue, in this case, is not whether such an adjustment should be made, but rather, what methodology should be used to make such an adjustment. In this area, the courts have held that the Board has power and discretion to choose any approach which rationally

> determines a subsidiary utility's effective tax rate. Toms River Water Company v. New Jersey Public Utilities Commissioners, 158 N.J. Super. 57 (1978).
>
> Based on our review of the record in this case, the Board **REJECTS** the ALJ's recommendation to accept the income tax expense adjustment proposed by Petitioner and, instead **ADOPTS** the position of Staff that the rate base adjustment is a more appropriate methodology for the reflection of consolidated tax savings. The rate base approach properly compensates ratepayers for the time value of money that is essentially lent cost-free to the holding companies in the form of tax advantages used currently and is consistent with our recent Atlantic Electric decision (Docket No. ER9009190J). Moreover, in order to maintain consistency with the methodology applied in the Atlantic decision, we modify the Staff calculation and find that a rate base adjustment which reflects consolidated tax savings from 1990 forward, including one-half of the 1990 savings, is appropriate in this case.
>
> [1993 JCP&L Order at pages 7-8].

Therefore, the question to be addressed by the Board in this proceeding is how these tax savings should be allocated among the affiliated companies and based upon this allocation whether or not an adjustment is appropriate in this case. JCP&L believes that a consolidated tax savings adjustment is not appropriate in this case because over the time in question, offsetting the tax losses by the positive income of only unregulated companies could have produced the tax savings. (PIB at 60). JCP&L further objects to the RPA' s adjustment in this proceeding stating that it is an ongoing, permanent rate base deduction that would remain forever, with no hope of ever turning around even if and when the utility's affiliates all consistently reported positive taxable income. (PIB at 61). The Board believes that Staff correctly points out that allocating all of the savings to the unregulated affiliates, as proposed by JCP&L in this proceeding, would be as arbitrary and unfair as it would be to allocate the entire savings to the regulated companies.

Regarding the specific methodology for calculating the consolidated tax savings, the Staff and RPA recommend that, in this proceeding, the "rate base" methodology be used to calculate any consolidated tax savings. (RAIB at 37-38; R-38, p. 16 Schedule 2, p.3; SIB at 46-47). However, the rate base methodologies proposed by the Staff and RPA differ in that the RPA calculates the savings on a year-by-year basis, where as Staff's methodology looks at the data over the entire period. Under Staff's methodology if a company has positive taxable income in some years and taxable losses in other years during the period analyzed, it will be able to offset its tax losses to the extent that it has sufficient taxable income in other years rather than having them shared amongst the positive companies. Staff believes this is appropriate, because it takes into account the fact that this type of company could utilize its net operating loss on a stand-alone-basis under the carry back and carry forward provisions of the Internal Revenue Code. (SIB at 47).

The Board believes that it is appropriate to reflect a consolidated tax savings adjustment where, as here, there has been a tax savings as a result of the filing of a consolidated tax return. The consolidated tax savings in question could not be achieved without the income of the affiliates with positive income and it would not be equitable to say that it was achieved by using the positive income of some companies but not others. Therefore, the tax savings should be allocated to each of the affiliates with positive income by their percentage share of positive income regardless of whether or not they are regulated or unregulated. Based upon this method of allocation, and JCP&L's percentage of positive income, it is clear that JCP&L did in fact significantly contribute to the consolidated tax savings through its positive taxable income. Further, the rate base approach recommended by Staff properly compensates ratepayers for the time value of money that is essentially lent cost-free to its affiliates in the form of tax advantages used currently and takes into account the fact that loss affiliates could utilize their net operating loss on a stand-alone-basis under the carry back and carry forward provisions of the Internal Revenue Code. Therefore, the Board **FINDS** that the methodology utilized by Staff and shown on Attachment A[14] to calculate consolidated tax savings is correct and **ADOPTS** the position of Staff that a consolidated tax savings adjustment in the amount of $36.9 million be made to the Company's rate base.

G. Revenue Annualization

JCP&L

JCP&L's weather normalization adjustment submitted in its 12+0 update decreases actual test year revenues by $13,106,000. As part of its adjustment, JCP&L uses an average customer level for the test year and does not account for any growth in the number of customers.

JCP&L rebuts the RPA's customer annualization adjustment, arguing that the RPA assumes growth for residential and commercial customers, but ignores the 1.0% erosion of JCP&L's industrial customer base. JCP&L also argues that it does not annualize its expenses to year-end levels but only annualized depreciation. (JC-4, at 2-3).

RPA

The RPA proposes an adjustment for customer growth to residential and small commercial customers based on growth rates of approximately 0.6% and 0.9% over the average number of year-end customers, resulting in an increase to the test year revenue for the residential and small commercial customer classes. (R-38 at 18). The RPA argues that failure to annualize customer growth occurring during the test year distorts the measurement of the income-producing capability underlying utility assets and overstates JCP&L's revenue requirement. The RPA's 12+0 year-end revenue annualization adjustment reflects a $2,255,000 adjustment for Residential customers and a $2,429,000 adjustment for General Service Secondary customers, for a total annualization adjustment of $4,684,000 to test year revenues. (R-38, DEP-1 (12+0), Schedule 3 at 3).

Staff

[14] Appendix SIB-1 to Staff's Initial Brief, Schedule S-Rev-4.

Staff notes that JCP&L used the year-end plant-in-service balance and annualized its depreciation expenses based on year-end plant. (JC-4 at 1-2). Staff asserts that in order to properly match revenues with test-year end rate base and annualized depreciation expenses based on year-end plant, revenues should reflect customer growth up to the end of the test year. (SIB at 50). Staff notes that the BPU has used this approach in previous base rate cases. (Ibid.).

Board Discussion and Analysis

Consistent with prior findings in other matters before the Board, the Board **HEREBY ADOPTS** the recommendation of Staff and the Ratepayer Advocate to include a $2,255,000 adjustment for Residential customer growth based upon a rate of 0.6% and $2,429,000 for General Service Secondary customer growth based upon a rate of 0.9%. The Board **HEREBY FINDS** the inclusion of revenues related to such growth is appropriate when matching revenues with the use of test-year end rate base and annualized depreciation expenses based on year-end plant. Also, as noted by Staff, the Company's argument that such an adjustment is selective as it includes customer growth for residential and commercial customers but ignores the erosion of the industrial customer base must be given little weight by the Board because the Company did not provide any alternative adjustment to reflect end of test year customer levels.

H. Clean Energy Program ("CEP") [Formerly "Comprehensive Resource Analysis"] - Lost Revenue Annualization

JCP&L

JCP&L proposes a test year revenue normalization adjustment of ($722,459), which reflects an annualization of CEP lost revenues associated with Board-approved energy efficiency programs implemented during the test year and included in JCP&L's proposed delivery charge. (JC-3 at 26). JCP&L asserts that its proposed adjustment to test year revenues is appropriate because the Board's DSM regulations permit the timely recovery of lost revenues and allow each utility to propose for consideration a mechanism to recover lost revenues. (JC-3 Rebuttal at 7). JCP&L asserts that lost revenue recovery for CEP programs is consistent with the Board Order in I/M/O the Petition of the Filings of the Comprehensive Resource analysis Energy Programs Pursuant to Section 12 of the Electric Energy Discount & Energy Competition Act of 1999, Docket Nos. EX99050347, EO99050349 et al., dated March 9, 2001, which adopted a utility proposal for CEP lost revenue recovery.

RPA

The RPA recommends that there be no annualized adjustment for CEP lost revenues in the 2002 test year, nor should CEP lost revenues be booked to the Demand Side Factor ("DSF") component of the SBC after 2002. (R-69 at 7-8). The RPA contends that utility recovery of CEP lost revenues is inappropriate because the Board has not approved the methodology for calculating savings and lost revenues, and because the proposed measurement protocols that have been submitted to the Board by the utilities would significantly overstate the impact on energy savings from new CEP programs. (R-69 at 9).

Staff

Staff agrees with the RPA that until the Board has made a final determination as to which programs, if any, qualify for lost revenue recovery and the methodology to calculate lost revenues associated with the CEP programs, the proposed annualized revenue adjustment of ($722,459) should not be included in the calculation of the delivery charge. The issue of measurement and verification of protocols remains pending before the Board, and Staff is still in the process of accurately verifying and measuring savings resulting from the implementation of energy programs. Until this review is completed, and until the Board has made a determination whether it is appropriate for the utilities to recover lost revenues, Staff recommends that JCP&L's requested recovery of lost revenues be denied.

Board Discussion and Analysis

The Board has not yet approved the appropriate protocols for verification and measurement of energy savings due to the Clean Energy Programs. However, until the Board has made a final decision regarding the measurement and verification protocols and appropriateness of the recovery of lost revenues pertaining to the Clean Energy Program, the Board **HEREBY FINDS** that JCP&L is permitted to defer its alleged lost revenues, as was recently approved by the Board in PSE&G's base rate case dated July 31, 2003, Docket No. ER02050303, et al. This would allow JCP&L to defer its lost revenues from May 2001 based on JCP&L energy savings as reported in the quarterly New Jersey Clean Energy Program reports filed with the Board, and subject to review by the Office of Clean Energy. If the Board subsequently determines in an appropriate proceeding that lost revenues are recoverable, the Company may file a Petition requesting recovery.

I. Charitable Contributions

JCP&L

The Company proposes to reclassify estimated contributions to charitable organizations from income deductions to operation expense resulting in a $752,000 adjustment to the Company's pro forma operating expenses. (JC-4 at 4, Schedule RFP-2, (12+0), JC-75). The Company argues that the bulk of these charitable contributions will be made by the FirstEnergy Foundation, which is a charitable foundation that supports non-profit, tax-exempt organizations in the service territories of the various utilities owned by FirstEnergy Corporation. (Ibid.). The Company asserts that most of the direct recipients of JCP&L's contributions are themselves customers of JCP&L and that all contributions reflected in the Company's proposed adjustment are targeted for New Jersey-based organizations. (JC-4 at 4-5). Pursuant to the Merger Order, the proposed adjustment does not include technology grants made to New Jersey schools and libraries.

JCP&L asserts that the RPA misapplies the NJAWC case, I/M/O the Petition of New Jersey American Water Company, Inc. for an Increase in Rates for Water and Sewer Service and Other Tariff Modifications, 169 N.J. 181 (July, 2001) arguing that the Court's opinion was premised on a finding that the Board's prior policy was arbitrary and not supported by the record in that case. JCP&L notes that it supports charities such as the United Way, youth programs, scholarship funds and other entities that are clearly consistent with the interests of its ratepayers and the communities in which they live. In addition, the Company's contributions to the American Red Cross, and local police, fire and emergency services directly benefit its customers and the communities they live in by increasing safety in these uncertain times. JCP&L notes that the Merger Order requires it to maintain its charitable commitments for three years after the merger. JCP&L asserts that the record in this proceeding provides the requisite factual support that was lacking in the NJAWC case.

RPA

The RPA opposes the Company's proposed adjustment for charitable contributions arguing that New Jersey American Water Company compels exclusion of charitable contributions from JCP&L's pro forma operating expenses.

Staff

Staff agrees with the RPA's interpretation of the opinion and recommends that charitable contributions be excluded from JCP&L's pro forma operating expenses. Staff rejects the argument by the Company that would narrow the ruling of the Court. Staff believes that the Court's clear language, strong expression of equitable considerations supported by decisions and opinions from courts of other jurisdictions provide an unambiguous and unmistakable directive compelling a broad reading of the Court's Opinion.

Board Discussion and Analysis

As noted by Staff, the New Jersey Supreme Court indicated "on general fairness grounds, the ratepayers should not be forced to pay additional amounts for charitable purposes at the hands of a regulated monopoly." I/M/O the Petition of New Jersey American Water Company, Inc. for an Increase in Rates for Water and Sewer Service and Other Tariff Modifications, 169 N.J. 193. It also emphasized "because a utility's charitable contributions are discretionary, they are more appropriately borne by the utility's shareholders, not its captive ratepayers." (Id. at 193) Accordingly, the Board agrees with the Ratepayer Advocate and Staff and **HEREBY FINDS** that all charitable contributions must be excluded from the Company's operating expenses.

J. Depreciation

Background

By letter dated March 1, 1995, JCP&L filed with the Board pursuant to 48:2-18 and N.J.A.C. 14:11-1.12 a petition seeking approval of changes to JCP&L's existing rates of depreciation on certain classification of its utility property ("1995 Depreciation Filing).[15] (JC-60). The Company did not seek any rate treatment for the proposed higher net amount of current depreciation expense that would result from the proposed changes but did reserve its right to seek prospective recovery of any new level of expense as part of its next base rate proceeding. Specifically, JCP&L requested the Board's approval of proposed changes to the Company's annual depreciation accrual rates and methodologies. The changes proposed by the Company would result in a decrease of

[15] In the Matter of the Petition of Jersey Central Power & Light Company for Approval of Changes to its Rates of Depreciation on Certain Classifications of its Utility Property Pursuant to N.J.S.A. 48:2-18 and N.J.A.C. 14:11-1.12, BPU Docket No. EO95030098, June 27,1996, March 24, 1997.

$8.6 million in accruals for its transmission and distribution plant, a decrease of $0.2 million in its general plant accrual (based on the FERC-approved change in accounting methodology), and an increase in the nuclear plant accrual of $10.2 million. The overall result of the proposed changes would be a net increase of $1.4 million to its annual depreciation accrual.

The 1995 Depreciation Filing was resolved by a Stipulation of Settlement ("Depreciation Stipulation") by the parties to the proceeding consisting of the Company, Board Staff and the Ratepayer Advocate and approved by the Board by Summary Order dated March 24, 1997.

JCP&L

JCP&L requests a net depreciation expense annualization adjustment of $1,515,000 and a total annualized depreciation expense of $114,847,000, which equates to an average overall depreciation rate of 3.39%, based upon depreciable plant (transmission, distribution, and general plant as of December 31, 2002). JCP&L reflects depreciation rates of 1.86% for transmission plant, 3.53% for distribution plant and 5.91% for general plant. (JC-25, JC-4 Schedule RFP-2 (12+0) at 6). The Company maintains that its proposal complies with paragraph 17 of the June 27, 1996 Depreciation Stipulation approved by the Board, by updating the book depreciation rate computations annually for plant additions, retirements, transfers and adjustments and keeping the negative net salvage rate percentages and depreciation service lives consistent with the separate Stipulation of Settlement of Depreciation Rates, also dated June 27, 1996, which also was approved by the Board as part of a Global Settlement.[16] (JC-17 at 5). JCP&L did not request or submit a depreciation study in this proceeding to change the negative net salvage percentages or service lives that were fixed in those stipulations approved by the Board. (Ibid.).

In response to the RPA's criticisms, JCP&L presented its witness Timothy H. Schad. Mr. Schad, a certified public accountant who has experience as a auditor with the Federal Energy Regulatory Commission ("FERC") and as a utility specialist in FERC's Office of Electric Power Regulation, testified that Financial Accounting Standard ("FAS") 143 does not impact the Board approved transmission, distribution, or general plant depreciation rates, including any negative net salvage components. (PIB at 102 citing JC-17 at 6). JCP&L asserts that the Federal Energy Regulatory Commission's proposed rulemaking supports its position that FAS 143 only relates to the accounting for Asset Retirement Obligations ("AROs") for financial statement reporting purposes. (JC-17 at 6-7). In fact, Company witness Schad, testified that FAS-143 does not bar recovery of negative net salvage even if not identified with any ARO. According the Mr. Schad, SFAS-143 applies to aspects of financial recordkeeping and not ratemaking determinations. (PIB at 102, citing JC-17 at 7). JCP&L does not object to filing an annual report of updates of its depreciation rates, but suggests that such a report should be submitted on April 30th of each year, consistent with the filing of the Annual Report to the Board. (JC-17 at 9).

---

16 I/M/O The Petitions of Jersey Central Power & Light Company for Approval of an Increase in its Levelized Energy Adjustment Charge, Demand Side Factor, Implementation Of a Remediation Adjustment Clause (RAC) Other Tariff Changes, Recovery of Crown/Vista and Freehold Buyout Costs, Changes in Depreciation Rates, Settlement of Phase 1 of the Board's Generic Proceeding on the Recovery of NUG Capacity Payments, Docket Nos. ER95120633, ER95120634, EM95110532, EX93060255, and EO95030098, (March 24, 1997).

The Company faulted the recommendation of RPA witness, Michael J. Majoros to capitalize the cost of removal as part of the cost of the replacement plant, gleaning from Mr. Majoros that he “was not sure or could not “recall any instance” where the Board ever approved such an approach. (PIB at 99, citing 9T101:2-16; JC-62). Additionally, Mr. Majoros acknowledged that the National Association of Regulatory Utility Commissioners (NARUC”) in its published depreciation manual entitled “Public Utility Depreciation Practices” (“Depreciation Manual”) supports the inclusion of future net salvage and cost of removal in current depreciation rates (PIB at 99-100, citing 9T103:2 to 104:1) and that the Board has adopted the principles set forth in the NARUC Depreciation Manual and includes future negative net salvage in the calculation of depreciation rates for New Jersey utilities. (PIB at 101, citing 9T118:11 to 119:14, See also New Jersey Natural Gas Company, BPU Docket No. GR8510974, June 20, 1986 [76 PUR 4^{th} 605 [[1986]]). Furthermore, Mr. Majoros admitted that “many, if not most”, regulatory commissions allow future negative net salvage or cost of removal in depreciation accrual rates for public utilities. (PIB at 100, citing 9T104:2-7). Mr. Majoros also admitted that the FERC Uniform System of Accounts recognizes salvage value and cost of removal as part of the setting rates for depreciation. (Id. citing 9T106:7-18).

RPA

According to the RPA, the Company’s depreciation expense is recovered by the Company in rates on a virtual dollar for dollar basis. (RAIB at 76). The RPA asserts that based on its analysis, the principle depreciation issue is the ratemaking treatment to be allowed by the Board for the Company’s estimated future net salvage, as it pertains to the Company’s annual depreciation expense. Additional issues raised by the RPA are whether the Board should require the Company to submit a report describing all aspects of its depreciation rate update calculations, and whether, on a going forward basis, the cost of removal of an asset should be charged to the cost of replacement of that asset. (Ibid.)

The RPA contends that JCP&L’s test year depreciation rates are excessive because they include an unsupportable and unreasonable request for negative net salvage (cost of removal). (RAIB at 77). According to the depreciation witness for the RPA, Michael J. Majoros, Jr., the Company proposes to collect $43.1 million for negative net salvage recovery in its test year depreciation expense for transmission, distribution and general plant. (RAIB at 77 citing R-64 at 12). Yet a review by Mr. Majoros over a five-year period ending 2001, showed that the Company had an average annual net negative salvage of only $3.9 million. (Ibid. citing R-64 at 17). This figure may be inflated since it includes production plant salvage and cost of removal, which function was removed from the Company and its rates pursuant to the Board Order in JCP&L’s restructuring proceeding. (Ibid.) The RPA argues that this figure is further increased through the inclusion by the Company of future inflation in its estimated net salvage expense which is eventually recovered by the Company in its rates. (Id. at 78, citing R-64 at 13). Mr. Majoros recommends removing JCP&L’s net salvage from its depreciation rate calculations, and replacing it with the five-year rolling average “net salvage allowance approach” used by the Pennsylvania, Kentucky, and Missouri Public Utility Commissions. (Ibid. citing R-64 at 17). Under this methodology, net salvage ratios are not calculated or included in depreciation rates, being replaced with a separate five-year average calculation of net negative salvage which is then added to the annual depreciation expense and included in the reserve. The RPA sees this approach as comparable to including a normalized expense into a utility's revenue requirement. (RAIB at 78).

The RPA argues that its recommended net salvage allowance approach is an approach recognized by the National Association of Regulatory Utility Commissioners ("NARUC") (R-66 at 158) and that its use in this proceeding fits squarely within the rationale contained in NARUC's depreciation manual.

The RPA further asserts that JCP&L's net salvage proposal is inconsistent with the principles regarding cost, capital recovery, and cost of removal. Specifically, pursuant to FAS143, the RPA contends that all companies must determine if they have actual legal obligations to remove retired assets. (RAIB at 39). If there is such an obligation, it is considered to be part of the cost of the asset. Here, however, JCP&L included negative net salvage in its depreciation rates, despite not having identified any associated AROs. (R-64 at 13 to 14). The RPA acknowledges that FAS 143 has not yet been adopted as a Generally Accepted Accounting Principle, but notes that the FERC is presently contemplating changes to the Uniform System of Accounts to recognize FAS 143. (R-64 at 14). The RPA believes that, in the absence of an ARO, the costs should be capitalized as part of the replacement to which they relate, or charged to expense in the case of abandonment, but not treated as part of the cost of the asset in a depreciation rate calculation because, in either case, by definition, there is no cost. (R-64 at 15).

The RPA argues that JCP&L's test year depreciation rates are different from the depreciation rates approved by the Board. (R-64 at 4). The RPA believes that JCP&L should submit a report to the Board and to the RPA providing all of the calculations underlying the annual filed updates. (R-64 at 5-6). The RPA contends that JCP&L calculated its test year depreciation rates using December 31, 2000 plant reserve balances. This is inappropriate because JCP&L now makes annual updates to its depreciation rates pursuant to the aforementioned stipulation.

The RPA asserts that JCP&L should be required to submit a report to the Board and the RPA by February 28 of each year identifying all aspects of its depreciation rate update calculations. (R-64 at 19). The RPA's updated exhibits propose a decrease of $37.701 million to JCP&L's updated 12-0 request. (R-38, DEP-1 (12+0), Schedule 3 at 2). This reflects the application of the RPA's proposed depreciation rates to JCP&L's updated plant balances at December 31, 2002, and the allowance of $4.8 million for the cost of removal, as reflected in JCP&L's test year budget for transmission, distribution and general plant.

Staff

Staff recommends adoption of the RPA's proposed depreciation rates which it believes is supported by FAS-143 and the concept of unbundled depreciation rate or rates that exclude the provision of the embedded cost of removal. (SIB at 91). Staff believes, however, that the cost of removal expense provision should reflect a broader (10-year) window of actual experience rather than the 5-year rolling average proposed by the RPA. Staff noted the RPA's observation that such data is problematic in this case because it includes production plant salvage and the cost of removal. (Ibid.). For purposes of the calculation in this proceeding, Staff agrees with the RPA's witness, Michael Majoros recommended level of $4.8 million as a net salvage allowance. Staff accepts the RPA's recommended depreciation expense of $77,146,000, resulting in an income adjustment of $22,300,000. (Ibid.).

Staff also concurs with the RPA that JCP&L should be required to submit an annual report to the BPU and the RPA providing all aspects of its depreciation rate update calculations. Staff accepts JCP&L's suggestion that the filing date be consistent with the filing date of its Annual Report to the Board. (Ibid.).

Board Discussion and Analysis

Net salvage refers to the difference between the gross salvage and the cost of removal of the plant. Gross salvage is the amount recorded due to the sale, reimbursement, or reuse of retired property. The cost of removal is connected to disposing of retired depreciable plant. Net salvage is positive when gross salvage exceeds cost of removal. Conversely, net salvage is negative when cost of removal exceeds gross salvage. A positive net salvage ratio reduces the depreciation rate and depreciation expense, while a negative net salvage ratio increases the depreciation rate and depreciation expense. In this matter, the RPA showed that the Company has incorporated $43.1 million of annual negative net salvage (cost of removal) recovery in its test year depreciation expense based upon currently approved depreciation rates, but over the five years ending 2001, the Company only experienced $3.9 million in negative net salvage on average, which amount includes net salvage on production plant that is not part of this case. As a result of this data and the underlying concept of FASB 143 as discussed in this matter, the Board **FINDS** it appropriate to revisit the concept of including estimated future net salvage in current depreciation rates. The Board **HEREBY FINDS** the recommendation of the Ratepayer Advocate and Staff to exclude estimated net salvage from depreciation rates to be appropriate. The Board **FURTHER FINDS** that the Ratepayer Advocate and Staff's proposed utilization of a five-year average of actual salvage expense in depreciation expense is reasonable as it more closely aligns the amount recovered in base rates with the historical level of expenses incurred. The Board concurs with Staff that the ten-year window of actual experience rather than the five-year rolling average proposed by the Ratepayer Advocate is appropriate. However, based upon the record in this matter as discussed above, the Board **HEREBY ADOPTS** a net salvage allowance of $4.8 million, which is the cost of removal reflected in the Company's test year budget.

K. Management Audit Expense: Amortization of Consultant Fees

JCP&L

JCP&L proposes a $142,000 increase to its test year operating expenses of $687,000, for a total annual amortization expense of $829,000, related to the recovery of Board-ordered management audit consultant fees. The resulting proposed amortization expense of $829,000 recognizes a three-year $519,000 annual amortization totaling $1,557,000 for expenses incurred for normal, periodic management audits for the years 1998 – 2002, and a four-year $310,000 annual amortization totaling $1,238,000 for expenses incurred for an extraordinary, one-time restructuring management audit.

RPA

The RPA recommends reducing JCP&L's test year management audit expenses by $100,000 related to the Phase 3 Outage Investigation Audit, and by $344,000 related to the Company's Reliability Audit. The RPA's proposal results in a $148,000 ($444,000/ 3 years) annual decrease in the Company's proposed expense, based on JCP&L's proposed three-year amortization for such expenses. The RPA reasons that JCP&L's actions preceding the outages were imprudent and that had it not been for those imprudent actions, the Phase 3 Outage investigation and the reliability audits would not have been necessary.

Staff

Staff disagrees with the RPA's disallowance of certain management audit expenses. Staff recommends a four-year amortization of the total audit expenses of $2,795,000 consistent with its use of a four-year amortization period for other items, such as rate case expenses. Staff recommends a total annual amortization expense of mandated management audits of $698,750, resulting in a net income adjustment of $77,000.

Board Discussion and Analysis

The Board **HEREBY FINDS** that a four-year amortization of the total mandated management audit expenses of $2,795,000, resulting in an annual amortization expense of $698,750, is appropriate in this matter. The Board agrees that a four-year amortization is reasonable for the Company to receive this level of management audit expenses, and is consistent with amortizations periods applied to other expenses in this matter. Consistent with N.J.S.A 48:2-16.4, the Board **FINDS** these costs reasonable for recovery on a four-year basis. The Board **HEREBY FINDS** no basis for disallowance of recovery of expenses incurred in association with the Company's Phase 3 Outage Investigation Audit and the Company's Reliability Audit as proposed by the Ratepayer Advocate.

L. GPU-FirstEnergy Merger Cost Accounting

JCP&L

In 2001, as part of the settlement and Board Order ("Merger Order") resolving JCP&L's merger proceeding, the Company wrote-off $300 million in funds accrued to the Company's Market Transition Charge/Basic Generation Service Deferred Balance.[17] (PIB at 73). The Company asserts that the $300 million write-off was intended to flow to the Company's customers savings anticipated from the merger and that this flow through of merger savings was made before such savings were actually realized. (Ibid.). The Company's shareholders were also allocated a portion of the net merger savings. JCP&L argues that the $300 million represents an actual amount the JCP&L paid to its energy suppliers pursuant to contracts in order to meet its Basic Generation Supply Service obligations. JCP&L asserts that in this rate proceeding it is proposing to provide its customers with an additional $21.5 million of net merger savings. (Ibid.) The $21.5 million represents $64.2 million of gross O&M merger savings reflected in the 2002 test year, net of $42.7 million of costs incurred to achieve those savings. (Ibid. citing JC-75). The $42.7 million includes $7,677,000 of test year costs related to the achievement of merger savings and

[17] I/M/O the Joint Petition of FirstEnergy Corp. and Jersey Central Power & Light Company, d/b/a GPU Energy for Approval of a Change in Ownership and Acquisition of Control of a New Jersey Public Utility and Other Relief, BPU Docket No. EM00110870 (October 9, 2001).

$35,019,000 of merger related costs incurred prior to the test year. JCP&L maintains that the recovery of these costs, including cost incurred prior to the test year consisting primarily of employee separation and information systems modification costs, (Id. at 76, citing JC-4 Rebuttal at 6) is justified because these costs were necessary to achieve the total merger savings that appeared in the test year. (Ibid., citing JC-81). JCP&L argues that the write-off mandated by the Merger Order provided $300 million of merger savings to customers, which constitutes an amount at least equal to all the merger savings that the Board deemed appropriate for allocation to customers and included the savings projected for 2002 and for many years beyond. (Ibid.). Accordingly, JCP&L argues that any additional net merger savings provided to its customers as part of this proceeding is improper since it would duplicate the savings already provided as part of the 2001 write-off and in effect "constitute a 'double helping' of merger savings" for its customers. (Ibid.).

RPA

The RPA asserts that JCP&L's proposal to recover any of the subject merger related costs is contrary to the Board's Merger Order and the Stipulation signed by the parties in that proceeding. (RAIB at 56, citing R-38 at 22). The RPA alleges that the Board's Merger Order specifically excluded recovery by the Company of certain merger related costs. According to the RPA the Company's ratepayers were not to include in their rate the following merger related costs: 1) consultant fees (including fees associated with financial, accounting, tax, and other services); 2) investment banker fees; 3) legal; 4) shareholder meeting and proxy expenses; 5) regulatory commission filing fees; 6) executive separation expenses; and 7) facilities, transportation and employee related costs. (RAIB at 57).

The RPA contends that the Board specifically accounted for merger related costs in its allocation to ratepayers of $300 million of an estimated $400 million of net merger savings and that, had the Board envisioned merger related costs as part of a future proceeding, it would have provided for a substantially greater allocation of gross merger savings in the merger proceeding, which then could arguably have been offset by the anticipated costs to achieve such savings. The RPA argues that approving JCP&L's request would allow JCP&L a double recovery of its merger related costs. (Id. at 58 citing R-38 at 22).

Staff

Staff notes that the Company identified and seeks recovery of merger related costs that were incurred in the test year and prior to the test year. (SIB at 61). The Staff disagrees with JCP&L's proposed treatment of merger related costs, including the proposed test year expenses, capital cost, and expenses incurred prior to the test year.

Based on the Staff's review of the Board's Merger Order, the Staff believes that the Board clearly ordered that $300 million of net merger saving be allocated to the Company's ratepayers at the conclusion of the merger proceeding. (SIB at 62-63). Staff thus agrees with the RPA that when the Board ordered the allocation of $300 million of the estimated $400 million in net merger savings to JCP&L's customers at the end of the merger proceeding, the Board envisioned that those net merger savings included the recovery of the estimated costs of achieving the gross level of merger savings over time. (SIB at 63). The Staff reasoned that if the Board intended to allow the Company to recover merger related costs a part of a future proceeding, then the

Board would have provided for a substantially greater allocation of gross merger saving in the merger proceeding. The Staff believes that in this way any future anticipated costs to achieve would be used as an offset to any gross savings. (SIB at 62-63).

Staff asserts that JCP&L's request for $35.019 million of pre-test year merger costs is flawed because: (1) it effectively seeks deferred accounting treatment of expenses on a retroactive basis; (2) it seeks treatment of merger costs that are already accounted for in the Board's implementation of net merger savings in the Merger Order, and (3) the approval of the request would build into JCP&L's rates an annual, recurrent recovery of costs that were actually incurred on a one-time basis to effectuate merger savings. Staff also asserts that JCP&L's request for recovery of $7.677 million of test year costs contradicts the Board's accounting of all merger related costs via the Merger Order, and would ensure the recovery of these one-time merger costs annually upon conclusion of this proceeding.

Board Discussion and Analysis

Having reviewed the record in this matter, the Board **HEREBY REJECTS** the Company's proposal to include a mechanism in rates to further address merger related savings and costs of $42,696,000 to achieve those savings, because the treatment of merger related costs and savings have already been addressed by this Board in its Order in the Merger Proceeding. Specifically, the Board's Merger Order acknowledged that the Company sponsored a merger synergy study that estimated merger synergy savings over the period 2001 –2011 would approach $1.6 billion net of approximately $335 million in costs to achieve those savings. Further, the Stipulation adopted by the Board's Order in the Merger proceeding provided that a net present value of $400 million of the total estimated $1.6 billion of merger savings would be assigned to JCP&L with $300 million allocated to the JCP&L ratepayers as a reduction to deferred costs that would otherwise be eligible for rate recovery in the post- transition period. The Order also acknowledged that ratepayers might benefit from the effect of any potential additional savings that would implicitly be reflected in future cost-of-service studies beyond those estimated in the merger synergy study. Given the Board's explicit rate treatment for the provision of merger savings and costs, the Board concurs with the positions of the Ratepayer Advocate and the Staff that it is inappropriate to build into rates $42,696,000 for merger related costs that appear to be incurred on a one-time basis to effectuate merger savings. The Board **HEREBY AFFIRMS** the Merger Proceeding Order as addressing all issues regarding the treatment of merger savings and costs.

M. SAP Project Enterprise/Evolution Amortization of Expenses

JCP&L

JCP&L proposes an adjustment to: (1) amortize its $17,400,000 investment in the SAP software system over its remaining three-year life producing an annual amortization of $5,800,000; and (2) amortize its $9,414,000 share of the cost of FirstEnergy System's new core business software platform (Project Evolution), which hardware costs are proposed to be amortized over three years, while the software and other costs would be amortized over seven years, for a total amortization amount of $1,697,000. JCP&L's proposed total amortization expense of $7,497,000 increases its test year amortization expense level of $4,985,000 by $2,512,000.

JCP&L contends that costs such as Project Evolution were not included in the Merger Order's list of specific merger costs that it was prohibited from using to reduce merger savings. It further asserts that Project Evolution costs were incurred to enable the merger savings to be realized, and should be recognized in determining the incremental net test year merger savings to be carried forward in rates.

RPA

The RPA argues that FirstEnergy's decision to implement a SAP system was a merger-related business decision. Costs associated with the Project Evolution portion of SAP should be deemed merger-related and no additional cost recognition or rate recovery of Project Evolution is necessary or justified. The RPA recommends a total annual SAP amortization expense of $5,800,000, based upon an expense reduction of $1,697,000 related to Project Evolution.

Staff

Staff agrees with the RPA with respect to its proposed SAP adjustment. FirstEnergy was not using the SAP system at the time of the merger and Project Evolution came out as an updated, integrated approach to integrate the FirstEnergy and GPU accounting systems.

Board Discussion and Analysis

For those reasons set forth in the Merger cost section of this Order, the Board **HEREBY REJECTS** the Company's proposal to include in rates those costs related to Project Evolution amounting to $1,697,000 in annual amortization expense. We concur with the positions expressed by Staff and the Ratepayer Advocate that these costs should be deemed as merger related costs and no additional recognition or rate recovery is warranted as the treatment of merger related costs have already been addressed in the Merger proceeding Order. The Company acknowledged that these costs relate to First Energy's decision to implement a SAP system for its own companies, a system First Energy was not using at the time of the merger but determined should be used to integrate the First Energy accounting system with the GPU accounting system. Accordingly, the Board **HEREBY ADOPTS** a total annual SAP amortization expense of $5,800,000 based upon an expense reduction of $1,697,000 related to Project Evolution.

N. Rate Case/Regulatory Expenses

JCP&L

JCP&L proposes to increase Pro Forma Operating Expenses by $783,000 for rate case expenses, based on a three-year amortization of $2,348,000, which it estimates will be incurred for legal fees and expenses, consultant fees and expenses, court reporter fees, public notices and postage, and messenger services associated with the instant proceeding. The proposed adjustment sets a normalized level of expenses, given the restructured regulatory environment.

JCP&L asserts that the estimated rate case expenses should be updated to the greatest extent possible, but notes that there will always be some estimated expenses because legal fees and other expenses continue to be incurred after the end of the test year. JCP&L argues that the Board has traditionally recognized that a certain "normal" level of rate cases expenses should be included in base rates and that a three-year amortization of rate case expenses is appropriate because such proceedings will continue to be required in the post-restructuring era.

JCP&L disagrees with the RPA's proposal to recognize only 50% of the rate case expenses of this proceeding. While acknowledging the Board's policy of a 50/50 sharing of rate case expenses between ratepayers and shareholders, it argues that the regulatory world has changed since its last rate case. JCP&L also notes that the initiative to file the instant proceeding was not theirs but rather that the Final Restructuring Order directed JCP&L to file the instant case. The Company argues that the Board should factor this consideration into its determination of whether to require a sharing of rate case expenses in this proceeding.

RPA

The RPA recommends: (1) that JCP&L's estimated rate case expenses be reduced from $2,348,000 to $2,000,000 until the actual amount becomes known; (2) a 50/50 sharing of rate case expenses, and (3) a five-year amortization of rate case expenses.

The RPA argues that the precise amount that JCP&L will spend on this proceeding will not be known for some time and that it is possible that the actual expenses will be significantly less than the estimated amount. The RPA notes the Board's policy allowing above-the-line treatment of only 50% of a major utility's rate case expenses. The RPA also contends that a three-year amortization of rate case expenses is unreasonably short because JCP&L's last base rate case was over ten years ago.

Staff

Staff agrees that rate case expenses continue to be incurred after the end of a test year. Staff recommends that the Board direct JCP&L to submit a revised estimate of its rate case expenses when it files its Exceptions to the Initial Decision. The Staff believes that this will allow the Board to make its determination using expense data that is current and accurate.

Staff recognizes that JCP&L was directed by the Board to file this proceeding; nevertheless, Staff sees no reason to deviate from the Board's long-standing policy of a 50/50 sharing of rate case expenses. While a rate case benefits the ratepayers through the continuation of safe, adequate and proper utility service, it also benefits shareholders, because the Company has a renewed opportunity to earn a fair return on equity. Staff recommends that JCP&L's rate case expenses be amortized over four years. Based on Staff's recommendations the Company will see a net income adjustment of $290,000 to its test year Pro Forma Operating Income.

Board Discussion and Analysis

Based upon the record in this matter, the Board **HEREBY FINDS** projected total rate case expenses of $2,348,000 to be reasonable. Consistent with the amortization period applied to other expense items in this matter, the Board **HEREBY ADOPTS** a four-year amortization period, as recommended by Staff, to be a reasonable provision for the Company to recover this level of rate case expenses. Further, the Board **HEREBY FINDS** that the circumstances in this matter do not warrant a deviation from long-standing Board policy to share rate case expenses on a 50/50 basis between ratepayers and shareholders. The Board concludes that an annual rate case expense of $294,000, as recommended by Staff, is appropriate for inclusion in rates in this proceeding.

O. Production-Related Regulatory Asset Amortizations

JCP&L

JCP&L proposes an increase of $4,892,000 to its test year amortization expense level of $1,049,000, by revising the amortization of five of its production-related regulatory assets which it has divested. The Board previously approved these regulatory assets for recovery using various amortization periods. Instead of utilizing these amortization periods, JCP&L proposes to use the assets' remaining balance as of December 31, 2002, and to amortize this balance over a four-year period, consistent with the restructuring transition period. This adjustment also includes an amortization of the Department of Energy Enrichment Facility test year fees over a four and one-half year period, consistent with the remaining DOE assessment period. This adjustment would transfer these fees from BGS to base rates, which JCP&L asserts is more appropriate, consistent with other production-related regulatory assets.

RPA

The RPA notes that none of the assets proposed to be amortized will be decommissioned until at least 2009, and that to accelerate the amortization for these regulatory assets without re-examining other issues simultaneously decided by the Board in its Restructuring Orders would upset the "delicate balance" struck by the Board in those cases. Accordingly, the amortization period originally approved for each asset should remain in effect until the remaining balances are recovered.

The RPA does not object to including DOE Enrichment Fees in base rates, provided that they are removed from base rates in approximately 2008 when the four and one-half year amortization period expires.

The RPA's recommendation to recognize the existing amortization level of $1,049,000 related to production-related regulatory assets, plus $2,288,000 related to the DOE enrichment fees, results in a total proposed amortization expense of $3,337,000, in comparison to the $5,941,000 expense sought by JCP&L, for a total expense adjustment of $2,604,000, thus increasing net income by $1,540, 000.

Staff

Staff concurs with the RPA that it would be inappropriate to accelerate amortization for the regulatory assets without simultaneously re-examining other elements of the Board's Restructuring Orders. Staff also agrees with JCP&L and the RPA regarding the transfer of DOE Enrichment Fees from BGS to base rates.

Board Discussion and Analysis

The Board **HEREBY FINDS**, consistent with the positions of Staff and the RPA, an alteration of the amortization of these assets as proposed by the Company is inappropriate. The Board agrees that without re-evaluating the issues previously decided by the Board in the prior proceedings where these amortization periods were approved, the delicate balance struck between the competing interests of ratepayers and shareholders might be upset. The Board **FURTHER FINDS**, consistent with the recommendations of the RPA, Staff and the Company, that the Department of Energy Enrichment Fees should be transferred from Basis Generation Service to base rates and amortized over the four and one-half year amortization period as proposed by the Company. Accordingly, the Board **HEREBY ADOPTS** an amortization expense of $3,337,000.

P. Restructuring Transition Costs

JCP&L

JCP&L proposes to include certain amortizations in its Pro Forma Operating Expenses associated with certain restructuring related costs which were approved by the Board in its Final Restructuring Order. The proposed adjustment increases JCP&L's Pro Forma Operating Expenses by $8,813,000 and represents a proposed eight-year amortization of a total of $70,500,000 in expenses, which includes $62,900,000 for Voluntary Enhanced Retirement Program Cost, $3,200,000 for Bridged Retirement Benefits and $4,400,000 for Voluntary and Involuntary Severance Payments.

JCP&L argues that the Board's Final Report and EDECA provide for rate recognition of certain restructuring related costs and that the Board approved the recovery of such costs over an eight-year period in its Final Restructuring Order. JCP&L notes that there was no regulatory proceeding in progress when these costs were written off, and argues that while accounting rules required them to be written off under those circumstances, that does not mean they should not be recovered in rates.

RPA

The RPA asserts that JCP&L's proposed amortization is for work-force reductions that occurred in 1996, two years prior to the enactment of the EDECA. The RPA asserts that EDECA was not intended to permit the retroactive resurrection of costs that were written off before it became law. The RPA argues that JCP&L's request is not an appropriate accounting or ratemaking practice and that JCP&L should have petitioned the Board in 1996 for permission to defer the charges.

Staff

Staff notes that the Board began its review of the future structure of the energy industry prior to the enactment of EDECA. Staff further notes that the Green Book issued by the Board prior to EDECA specifically proposed that any costs incurred as a result of utility downsizing or reorganizations related to industry restructuring are appropriately addressed through base rates. The Legislature made similar findings in EDECA.

Staff believes that both the Board and the Legislature intended that New Jersey's electric utilities recover through their respective rates reasonably incurred restructuring related employee separation costs, including the costs of severance pay. Accordingly, Staff recommends allowing JCP&L $8,813,000 in test year operating expenses for the amortization of employee related restructuring transition costs.

Board Discussion and Analysis

Based upon events, as noted by Staff, pertaining to the time period of the Board's review of the future structure of the energy industry, the Board's issuance of the Green Book, the Board's March 7, 2001 Order referenced by the Company above, and the findings of the Legislature with respect to restructuring related costs, the Board **HEREBY ADOPTS** the Company's proposal to include $8,813,000 in test year operating expenses. This represents an eight-year amortization period of the Company's restructuring transition costs of $70.5 million.

Q. Incentive Compensation Expense

JCP&L

JCP&L has several employee incentive plans, encompassing its management, professional, administrative and bargaining unit employees. Each plan includes Key Performance Indicators ("KPIs") that correspond to the performance objectives for each employee group. The KPIs vary from one employee group to another, but commonly include key measures related to productivity, cost reduction, and customer satisfaction. The Company asserts that its plans are significantly weighted toward operational measures rather than financial measures, since operational measures focus on its customers' main concerns.

The Company argues that incentive compensation is a necessary component for any organization, if that organization is to attract and retain talented and capable employees. The Company notes that since its last base rate case, there is an upward trend of companies offering incentive compensation plans for their employees. The Company further argues that: (1) tying pay to performance can reduce costs and improve productivity; (2) incentive compensation is a tool that allows employers to focus employee efforts on specific goals and to reward higher performance; (3) competitive pressures, brought on by deregulation, have created a significant role for incentive compensation in utilities; and (4) incentive plans align the interests of all stakeholders, including the Company's employees, shareholders, and its customers.

The Company contends that unions have become much more accepting of incentive pay plans and that JCP&L's incentive plans covering union employees include specific operational measures that have been specifically negotiated between the union and management.

The Company believes that it would be a step backward if the Board rejected all or part of the Company's proposal to include incentive pay in its test year operating expenses. The Company believes that base pay alone does not recognize performance, is not tied to the wants or needs of its customers, and could lead to a decline in its employees' job performance.

RPA

The Advocate recommends excluding Incentive Compensation Expense of $4,818,000, from JCP&L's test year operating expenses. The Ratepayer Advocate disagrees with JCP&L's argument that the Company's customers benefit from all of the incentive compensation plans. According to the RPA, the stated objectives of certain incentive compensation plans place shareholder gain as the primary goal of each plan. The Advocate believes that since FirstEnergy's shareholders are the intended primary beneficiaries of those incentive compensation plans, FirstEnergy's shareholders should bear the cost responsibility for those incentive pay plans. The Ratepayer Advocate did not object to the inclusion of the remaining incentive compensation related to payments for operational goals to certain union regional goals, meter readers and customer service representatives.

Staff

The Staff notes that the in two prior decisions, the Board considered the issue of incentive compensation for ratemaking purposes. I/M/O Jersey Central Power and Light Company, BPU Docket No. 91121820J (June 15, 1993), ("1993 JCP&L proceeding"); and I/M/O the Petition of Middlesex Water Company, BPU Docket No. WR00060362 (June 6, 2001), ("Middlesex"). In those decisions, the Board expressed its belief that incentive compensation expenses should not be included in the expenses allowed for recovery by a utility in the rates charged to its customers. The Staff believes that the underlying reasoning supporting the Board's rejection of incentive compensation in the 1993 JCP&L and Middlesex proceedings remains valid today and continues to provide a basis supporting the disallowance of the amount requested by the Company for its Incentive Compensation Expenses, where the stated objectives of the incentive compensation plans place shareholder gain as a primary goal of the plan. Staff also noted that JCP&L now has several incentive compensation plans and that these incentive compensation plans are made available to a significantly wider array of employees that at the time of the Board's 1993 JCP&L Order. Staff concurred with the recommendation of the Ratepayer Advocate to include incentive compensation related to payments for operational goals to certain union regional goals, meter readers and customer service representatives. Accordingly, Staff concurred with the recommendation of the Ratepayer Advocate that $4,818,000 in incentive compensation expenses be excluded from JCP&L's test year operating expenses.

Board Discussion and Analysis

In accordance with long-standing Board policy on the issue of management incentive compensation, the Board **HEREBY FINDS** the recommendations of the Ratepayer Advocate and Staff to disallow $4,818,000 of the Company's total incentive compensation expenses to be reasonable for two reasons. First, as was the case at the time of the Board's findings in JCP&L's 1993 Order, today's economic conditions also do not justify passing the cost of incentive compensation through to ratepayers for programs that primarily benefit shareholders, especially when it is evident that many ratepayers, homeowners, and businesses alike, are having difficulty paying their utility bills or otherwise remaining profitable. Secondly, the treatment recommended by the Staff and the Ratepayer Advocate is fair and reasonable given that it recognizes that incentive compensation plans have been made available to a wider array of employees since was the case in 1993 and such plans cover union employees and include specific operational measures that have been specifically negotiated between the union and management.

R. Miscellaneous Expenses

JCP&L

JCP&L asserts that it eliminated institutional, goodwill, and image advertising from its test year expense consistent with the Board's policy regarding advertising expenses. JCP&L argues that the subject advertising expenses were informational in nature and related to a customer education campaign to inform customers about the reintroduction of the JCP&L name. JCP&L avers that the nature of the advertising for which it seeks recovery is not mere image building, but related to community affairs and public relations activities that are encouraged or required by the Board. JCP&L asserts that it is important for customers to know who to call in emergency situations or to how to obtain information about its services and programs and argues that this type of informational advertising is clearly appropriate for rate recovery.

RPA

The RPA proposes to exclude costs associated with community affairs, public relations, and image advertising from JCP&L's test year operating expenses. The RPA believes that JCP&L's ratepayers should not be required to pay JCP&L for its commitment to meets its customer service obligations. The RPA asserts that excluding public relations and image advertising from a utility's revenue requirement is consistent with Board policy. The RPA proposes to exclude $167,000 for public relations expenditures, $605,000 for image building expenditures, and $186,000 in "other" expenditures from test year operating income, producing a total $958,000 reduction to test year operating expenses and a $567,000 increase to test year operating income.

Staff

Staff reviewed samples of JCP&L's bill inserts, print ads, and radio scripts and based upon its review, notes that the Company's bill inserts were designed to inform customers about rates, the number to call in case of a power outage, safety guidelines, how to read an electric meter, conserving energy and/or water, low income programs such as Lifeline, and other essential information. Accordingly, Staff agrees that the costs associated with bill inserts meet the Board's guidelines for informational advertising and should be included in test year operating expenses.

However, the print advertisements and radio scripts associated with the reintroduction of the JCP&L name and the Company's renewed commitment to reliability and customer service are, in Staff's opinion, clearly designed to enhance the goodwill, credibility, reputation, character or image of the Company, and thus fit the Board's definition of institutional advertising, and should be excluded from test year operating expenses. This results in a $605,000 reduction to test year operating expenses.

Consistent with its recommendation regarding the JCP&L's proposal to reclassify contributions to charitable organization from income deductions to operating expenses, Staff further recommends that the expenses associated with the American Red Cross, the Freedom House Foundation, the New Jersey Conference of Mayors, the New Jersey

Builders Association, the Northeast Sustainable Energy Association, and for individual memberships be excluded from test year operating expenses. This results in a $186,000 reduction to test year operating expenses.

Staff noted that actual test year operating expenses include $167,000 for public relations and community affairs expenses. While the above-described items are designed in part to inform the public about regulatory matters, public safety and energy conservation, these items are also designed to enhance JCP&L's image. JCP&L did not provide a separate breakdown of the individual expense items. Therefore, the Staff recommends disallowing the entire $167,000 for Community Affairs and Public Relations expenses from JCP&L's operating expenses.

Board Discussion and Analysis

In the past, the Board has held that expenses associated with informational advertising should be reflected in rates and that the expenses associated with institutional and/or promotional advertising should be disallowed for ratemaking purposes. The Company testified that the subject advertising expenses were informational in nature because they related to a customer education campaign to inform customers about the reintroduction of the JCP&L name and to emphasize the Company's commitment to reliable service. The Board **HEREBY FINDS** that ratepayers should not be required to pay JCP&L to publicize its commitment to meets its customer service obligations. Moreover, based upon a review of the samples of JCP&L bill inserts, print ads and radio scripts, the Board **FURTHER FINDS** that these were primarily designed to enhance the goodwill, credibility, reputation, character or image of the Company or increase the demand for utility service and are not eligible for recovery in base rates. Therefore, the Board **HEREBY FINDS** that $958,000 should be disallowed from JCP&L's miscellaneous expenses as recommended by the RPA.

S. Interest Synchronization

JCP&L

JCP&L proposes an adjustment to synchronize that portion of its Federal Income Tax expense associated with rate base and the weighted cost of debt utilized to support rate base. It includes the Weighted Cost of Monthly Income Preferred Securities ("MIPS") in its proposed adjustment, asserting that this is consistent with prior Board Orders.

JCP&L disputes the RPA's use of a different capital structure from that proposed by JCP&L. It argues that the RPA's capital structure includes a level and assumed cost on non-existent debt that distorts JCP&L's actual existing level of debt and related interest expense, creating an interest synchronization that is misleading and inaccurate.

RPA

The RPA proposes to modify JCP&L's adjustment to reflect its recommended level of rate base and the weighted cost of debt. The weighted cost of debt component in the RPA's interest synchronization proposal does not include MIPS.

Staff

Staff agrees with the Company's methodology. Staff included MIPS in the weighted cost of debt component of its interest synchronization calculation because MIPS is a form of long-term debt and the intent of an interest synchronization adjustment is to synchronize the Federal Income Tax expense associated with rate base and the weighted cost of debt utilized to support rate base. Staff's interest synchronization adjustment results in a total adjustment to test year interest expenses of $15,565,000 and a $6,358,000 increase to Pro Forma Operating Income.

Board Discussion and Analysis

The Board **HEREBY FINDS** the Staff's position on interest synchronization to be consistent with the Board's policy to synchronize interest expense in the Federal Income Tax expense calculation by applying the weighted cost of debt to support rate base, including MIPS, to that rate base. The Board **FURTHER FINDS** that the Staff position has been modified to reflect the Board's other findings herein. The Board **HEREBY ADOPTS** $80,482,000 as an appropriate interest expense for the purposes of interest synchronization.

T. Taxes Other Than Income Taxes – Gross Receipts and Franchise Tax ("GRFT")

JCP&L

JCP&L disagrees with the RPA's proposed adjustment. JCP&L argues that this issue was raised by the RPA for the first time in its 12+0 Updates. JCP&L urges the Board to reject a single post-test year adjustment that fails to recognize all potential post-test year changes.

RPA

In order to remove an expired Gross Receipts and Franchise Tax amortization, the RPA proposes to reduce JCP&L's requested allowance for Taxes Other Than Income Taxes of $65,965,000 by $8,835,000. The RPA's proposal would reduce the allowance to $56,152,000 and increase Pro Forma Operating Income by $5,226,000.

Staff

Staff agrees with the RPA's adjustment. Citing In re Elizabethtown Water Company Rate Case, BPU Docket No. WR85040330 (May 23, 1985), wherein the Board determined that it would recognize known and reasonable adjustments outside the test year, Staff argues that because the GRFT Amortization expires only two months beyond the test year, the RPA's proposed adjustment is appropriate.

Board Discussion And Findings

As noted by the Ratepayer Advocate and supported by Staff, this Gross Receipts and Franchise Tax amortization of $8,835,000 had expired two months beyond the end of the test year in this matter and well within the six month period the Board has allowed for consideration of post test year adjustments. Accordingly, the Board **HEREBY** **ADOPTS** the Staff and the Ratepayer Advocate's position on this issue.

U. BPU & RPA Assessments Adjustment

JCP&L

JCP&L proposes an adjustment reflecting the normalization of the BPU's and RPA's assessments based upon normalized test year revenues and estimated assessment rates in the amount of $848,000. It proposes to allocate this adjustment by allowing $287,000 for the RPA assessment and $561,000 for the BPU assessment. JCP&L argues that the RPA failed to use the latest known assessment rates.

RPA

In its 12+0 updates, the RPA used the assessment rates that applied to payments made by JCP&L in 2002. This 12+0 adjustment reflects a total $22,000 adjustment to BPU and RPA assessments or a negative net $13,000 income tax adjustment. Specifically, the resulting BPU pro forma assessment is $3,705,000 compared to $3,687,000 as proposed by the Company and a RPA pro forma assessment of $926,000 as compared the Company's filed $922,000.

Staff

Staff supports the RPA's 12 + 0 adjustment because it (1) accounts for the growth in the level of customers; (2) utilizes the most recent assessment rates, and (3) includes a tax adjustment.

Board Discussion and Analysis

The Board having reviewed the record in this proceeding **HEREBY** **FINDS** that for the reasons articulated by Staff regarding the BPU/RPA assessment the recommendations made by the RPA and Staff are appropriate. Accordingly, the Board **HEREBY** **ADOPTS** the 12+0 adjustment reflecting a $22,000 adjustment to the BPU/RPA assessments.

V. Service Reliability

JCP&L

JCP&L asserts that the service reliability issues which the RPA raises are not relevant to this rate proceeding, but rather relate to separate service reliability proceedings instituted by the Board pursuant to N.J.S.A. 48:2-25.

RPA

The RPA assessed JCP&L's reliability related policies, technical standards, performance standards and maintenance practices, such as age/loading of transformers, tree-trimming practices, and stray voltage events. The RPA asserts that JCP&L's customers have long endured severe and prolonged power outages, which on two recent occasions resulted in formal investigations by the Board.[18] The RPA further notes that in the Merger Order, the Board conditioned its approval of the merger upon specific Board concerns with staffing levels, reliability, and customer service performance.. The RPA further notes the Board's most recent investigation of JCP&L, in I/M/O the Board's Investigation Into JCP&L's Storm-Related Outages of August 2002, BPU Docket No. EX02120950 (March 13, 2003), questioned the Company's storm response and the overall reliability of its electric distribution system.

Staff

Staff notes the Board's previous expression of serious concern regarding JCP&L's restoration performance in BPU Docket No. EX99100763 (the "Phase I Order"), dated April 28, 2000 and in BPU Docket No. EA9907485 (the "Phase II Order"), dated May 1, 2000, wherein the Board adopted reports by its consultants, Stone & Webster Management Consultants.[19] As a result of several investigations since 1997, the Board ordered JCP&L to implement corrective measures to mitigate the impact of storm related outages and improve overall service reliability to address some of the issues raised by the RPA. These included a Circuit Action Plan, a Recloser Program, installation of a Supervisory Control and Data Acquisition ("SCADA") system, substation transformer testing and maintenance practices, and tree-trimming programs.

Staff believes that investigations similar to the Phase I and II reviews of specific events and periodic management audits focusing on reliability issues, including those issues raised by the RPA, are reasonable approaches to address reliability concerns, which should assist JCP&L in improving its level of reliability. Staff recommends that the issues raised by the RPA should continue to be addressed in other reliability-related proceedings currently or prospectively before the Board.

Board Discussion and Analysis

The Board has long had a concern with reliability in JCP&L's service territory. The Board has conducted and is currently conducting reviews and focused audits related to service problems. There have been a number of outages in recent summers, most notably in 1999 in Red Bank. I/M/O the Proposal to Perform a Review and Investigation of New Jersey's Electric Utility Systems, in Docket. No. EX99070483 and I/M/O the Review and Investigation of New Jersey's Electric Utilities' System Reliability, in Docket. No. EX99100763. In the record of the instant base rate case, the RPA raised a number of concerns pertaining to service quality and reliability and made a series of proposals, including the establishment of performance standards.

---

[18] I/M/O the Investigation into Storm Related Electric Service Outages, BPU Docket No. EX 98101130 (December 12, 1998); I/M/O Board's Review and Investigation of GPU Electric System's Reliability, BPU Docket No. EA99070485 (April 26, 2000).

[19] See In the Matter of the Board's Phase Three Review and Monitoring of the Implementation of the Recommendations from the Board Ordered Phase Two Review and Investigation of New Jersey's Four Electric Public Utilities, BPU Docket No. EX99070483 (June 7, 2001).

The Board itself has taken several measures to increase service quality and reliability in JCP&L's service territory. For instance, an investigation is being performed on JCP&L's storm response in August 2002, I/M/O Jersey Central Power and Light Company Storm Restoration Effort for the August 2, 2002 Outages, in Docket. No. EX02120950 dated March 13, 2003.[20]

By Order dated July 16, 2003 in Docket. No. EX03070503, this Board directed the Company to take immediate action to address the problems it experienced during the 2003 summer. In addition, as a result of the outage problems experienced over the July 4, 2003 weekend by JCP&L customers in the shore areas, the Board is reviewing an expedited action plan, including the appointment of a Special Reliability Master to oversee necessary reliability improvements in an expedited manner.[21]

The Board further believes, however, that, as part of its decision in this case, it is appropriate that additional measures be taken to improve JCP&L's system-wide reliability, as discussed below.

1. Measurement and Analysis of JCP&L Reliability Performance

The Board **HEREBY FINDS** that both the arguments of the RPA and Staff are persuasive, in light of documented events adversely affecting the Company's customers. The Board further **FINDS** merit in Staff's recommendation that reliability and service quality issues should be addressed in other reliability-related proceedings currently or prospectively before the Board. The Board therefore **HEREBY ORDERS** that a Phase II proceeding ("Phase II Proceeding") be conducted to review whether the Company is in compliance with current service reliability and quality standards set forth in N.J.A.C. 14:5-7 and to address whether additional performance standards are required for JCP&L, such as specified targets to improve JCP&L's reliability and service quality in the shore area, on both a short-term and long term basis, as well as to improve service quality and reliability throughout JCP&L's entire service territory. Such improvements must be undertaken immediately by the Company in the most expedited and efficient manner. It is anticipated that the results of the current ongoing reviews and focused audits, including the review of the Special Reliability Master, will be considered in the Phase II Proceeding.

The Board further **APPROVES** Staff's recommendation that the Company be ordered to segregate on its books all capital expenditures related to improvements of its system. Any such expenditures and projects undertaken by JCP&L to increase its system's reliability will be reviewed as part of the Phase II proceeding, to determine their prudency and reasonableness for rate recovery.

[20] On September 24, 2003, the Board hired Booth & Associates to perform an investigation of the Company's overall system reliability and to recommend specific areas for improvement.

[21] On August 1, 2003, the Board retained the Special Reliability Master to investigate the events leading to the July 2003 outages and to make recommendations to mitigate such occurrences in the future.

2. Service Quality Index

JCP&L

In its reply brief, the Company responds to the proposal by RPA to subject JCP&L to a Service Quality Index requiring the Company to maintain certain levels of service quality and reliability. The Company believes that the reliability issues raised by the RPA do not and should not be considered as part of the pending base rate proceeding. The Company argues that the Board has not adopted the service and reliability standards proposed by the RPA. JCP&L maintains its belief and recommendation, which the Company asserts is supported by Staff, that the standards and mechanisms embodied in the RPA's proposals should be considered within a comprehensive process developed under the Board's auspices and rulemaking authority.

RPA

The RPA, through its witness Barbara Alexander, proposes that JCP&L be subject to a Service Quality Index that requires the Company to maintain historical levels of service quality and reliability and imposes financial penalties in the form of rebates to customers for the failure to maintain these performance standards on an annual basis. The performance standards would not only apply to duration and frequency of outages, but also to such areas as call centers, residential customer installation of service, and customer complaint ratio.

In 2000, the BPU adopted Interim Electric Distribution Service Reliability and Quality Standards, codified at N.J.A.C. 14:5-7 (effective January 2, 2001). These Standards establish a minimum service reliability level for each electric utility consistent with the recommendations of the Reliability Working Group established by the Board. The Reliability Working Group consists of representatives of the electric utilities, the RPA and Staff. The Reliability Working Group reviews the current reliability standards and reports to the Board on recommendations for further action.

Ms. Alexander further testified that in late 2002, the Board stated that it intends to adopt permanent standards with penalties for noncompliance that would be applied automatically. However, the Board has not initiated any proceeding to implement this proposal. Ms. Alexander noted that until these permanent standards are established, there are no automatic penalties or other enforcement actions that are linked to failure to maintain the stated reliability performance levels.

Staff

Staff agrees with the RPA that there is a need to establish permanent reliability standards with penalties for noncompliance. However, Staff believes that these standards should apply to all the electric utilities at the same time and for that reason the Board had established the Reliability Working Group Process. In late 2002, this Reliability Working Group initiated the process and has conducted meetings in order to work on the interim standards and establish permanent standards. In those meetings, the four electric utilities indicated that they had either completed or were close to completing their new Outage Management System ("OMS") and it would require them three to four years to perfect the OMS in order to collect the reliable data upon which the permanent standards could be based.

Subsequently the Reliability Working Group jointly decided that pending completion of the new OMS, there was insufficient data that could be relied upon in order to make meaningful permanent standards, and that the utilities would collect OMS data until year 2005 before the Reliability Working Group recommends permanent reliability standards.

Staff believes that these permanent standards should have other customer service metrics such as timeliness of installation of service, call center performance, accuracy and customer complaint performance. Staff recommends that any reporting requirements, benchmarks or performance standards on these metrics should be established at the same time the permanent standards are developed in 2005.

Board Discussion and Analysis

The Board **FINDS** that the establishment of a service quality index, as proposed by the RPA and supported by Staff, to tie financial penalties to levels of service quality and reliability, is not appropriate at this time. However, the Board **FINDS** that Staff's recommendation regarding the establishment of industry-wide permanent standards for measuring service quality and reliability should be initiated as early as practicable. The Board therefore **DIRECTS** Staff to reconvene the Reliability Working Group to review the Board's existing Interim Electric Distribution Service Reliability and Quality Standards, N.J.A.C. 14:5-7, and to recommend any modifications relating to the establishment of such permanent standards. Also, the Board will review the results of the Booth audit, and the Report of the Special Reliability Master which may result in specific performance criteria to assure improvements in reliability throughout JCP&L's service territory..

W. COST OF SERVICE / RATE DESIGN

1. Cost of Service

JCP&L

JCP&L's Cost of Service Study ("COSS") follows the traditional process of functionalization, classification, and allocation of costs to rate classes based on year 2002 balances. Except for the Yards Creek and Forked River generating stations, JCP&L no longer owns generating assets. JCP&L's study reflects this by including only the costs to transmit and distribute power to its customers. The functionalization of its power delivery asset costs into transmission-related, and distribution-related components is based on the FERC Uniform System of Accounts. JCP&L's common costs, however, were not functionalized but, instead, allocated directly to rate classes. The functionalized costs were classified into demand, energy, and customer components, and then allocated to rate classes based on the Company's determination of each rate class's respective cost responsibilities.

JCP&L separated transmission plant costs into bulk transmission, subtransmission, and distribution subfunctions on the basis of facilities operating at greater than or equal to 115 kV, equal to 34.5 kV and less than 34.5 kV, respectively. It also separated distribution plant based on primary and secondary subfunctions using ratios determined in prior cases. It applied these ratios to separate costs associated with FERC plant accounts 364 through 368. JCP&L used a voltage specific average and excess allocation method to allocate the transmission and distribution plant cost to rate classes.

JCP&L asserts that it constructed its COSS using the same general methodology and traditional principles as were used in prior studies accepted by the BPU in previous proceedings, wherein the Board recognized that there is both a demand and energy component associated with transmission and distribution system costs, and adopted the voltage level specific average and excess methodology for the classification and allocation of transmission and distribution costs ("Average and Excess method).[22]

The Company performed certain modifications to aspects of the Average and Excess method approved by the Board in prior cases. First, the Board-approved COSS allocated secondary distribution facilities to all customer rate classifications regardless of whether these customers were connected to both the primary and secondary distribution portions of JCP&L's system. JCP&L's COSS excludes assignment of secondary distribution costs to the General Service Primary ("GP") class. Second, the Board-approved studies allocated a portion of the sub-transmission (34.5 kV) facilities' costs to customers served directly from the bulk transmission (230kV) assets. JCP&L's study does not perform the same allocation. Third, the Board accepted the demand allocator using the average of the four summer monthly non-coincident peak demands. JCP&L's cost of service study uses a single non-coincident peak demand in formulating its Average and Excess cost allocators.

The results of the Company's proposed COSS depict Rate Classifications Residential Service ("RS"), Residential Time-of-Day Service ("RT"), General Service Secondary Time-of-Day ("GST") and Lighting Service ("LTG") as presently earning less than JCP&L's rate of return, while Rate Classifications General Service Secondary ("GS"), and General Service Transmission ("GT") are earning rates of return higher than the Company's average of 10.21% (11.25% update). Under JCP&L's COSS, the present unitized rates of return for rates classes RS, RT, GST, and LTG are less than one and for rate classes GS, GP, and GT are greater than one. JCP&L relies on this result to allocate its proposed distribution revenue decrease to bring the classes' unitized rates of return closer to unity. Consequently, JCP&L proposed that the RS, RT, GST, and Lighting classes receive a rate increase of $6.4 million with the GS, GP, and GT classes receiving a $19 million decrease.

RPA

The RPA advocates a cost allocation which is based on a stricter adherence to the Board's previously approved methodology. The RPA criticizes JCP&L's use of a single non-coincident peak demand in developing its Average and Excess cost allocations arguing that this approach fails to recognize the importance of stability in the Average and Excess allocators used to assign costs for the bulk of JCP&L's delivery assets to its rate classes. Moreover, the RPA argues that JCP&L's proposed change significantly impacts the unitized rates of return for each of the customer classes.

---

[22] I/M/O the Petition of Jersey Central Power and Light Company for Approval of an Amendment to its Tariff to Provide for an Increase in Rates and Charges for Electric Service, BPU docket No. ER89110912J (April 9, 1992) ("1992 JCP&L Order); I/M/O the Petition of Jersey Central Power and Light for Approval of Increased Base Tariff Rates And Charges for Electric Service and Other Tariff Revisions. BPU Docket No. ER91121820J, (June 15,1993). ("1993 JCP&L Order").

The RPA argues against using a single non-coincident demand allocator even if the distribution system is sized to meet JCP&L's claimed single maximum peak. The RPA believes that if sizing provided the only basis for allocation, then all costs associated with load-bearing equipment would be allocated on the basis of demand. The RPA contends that in JCP&L's last base rate proceeding, the Board rejected the exclusive use of demand based allocation methods for transmission and distribution costs. In addition, the RPA references the Electric Utility Cost Allocation Manual*,* published by the National Association of Regulatory Utility Commissioners, as supporting the acceptance of a wide-range of allocation methods, including monthly coincident and non-coincident peaks ranging from one to twelve months, and that sizing to meet a single peak does not act to determine allocation.

Contrary to the Company's assertion, the RPA argues that the Board approved Average and Excess methodology would move the unitized rates of return for rate classes RS, RT, GST, and Lighting closer to unity than the Company's modified methodology. According to the RPA, using the current Board approved methodology increases the unitized rates of return for the RS and RT rate classes from 0.76 to 0.83 and 0.72 to 0.97 respectively. For the GS, GP, and GT rate classes, the unitized rates of return decrease from 1.23 to 1.13, 1.62 to 1.44, and 3.76 to 3.49, respectively. Based on these results, the RPA recommends minimal decreases to all rate classes.

For distribution revenue decreases larger than $12.6 million the RPA recommends allocating about 80% of the decrease among the GS, GP and GT dasses until their unitized rates of return are at unity. The balance of the decrease would be allocated to all classes on a kwh usage basis.

Staff

Staff observes that the current Average and Excess methodology as approved by the Board in the 1992 and 1993 JCP&L Orders and the Board's 2001 final decision in restructuring represents the Board's long-standing policy regarding the allocation of costs and the establishment of distribution rates.

First, Staff disagrees with the Company's use of a single non-coincident peak and argues that JCP&L ignores the Board's considered judgment in adopting the use of the average of four non-coincident peaks in the 1992 and 1993 JCP&L Orders. Thus, a departure from the Board sanctioned calculation of average and excess allocators distorts the results of the Cost of Service Study and leads to the derivation of unjust and unfair class distribution rates

Second, Staff believes that by not assigning any secondary distribution costs to the GP class, JCP&L improperly deviates from the Board's long-standing policy. Staff asserts that the Company's proposal will produce a substantial difference in the allocation of distribution costs between the primary and secondary classes from that allocated to these rate classes in previous cases and effectively shift the bulk of these costs to the secondary classes. Moreover, the present regulatory environment has not altered the basic principles underlying system operations and planning, leaving prior Board decisions on allocating secondary distribution valid.

Staff argues that by utilizing ratios which separate distribution plant into primary and secondary subfunctions that are different than previously used and approved by the Board, JCP&L over-allocated $54,351,277 in costs to rate class RS and $5,815,813 to rate class RT, while under-allocating costs of approximately $30,000,000 to rate class GS, $23,000,000 to rate class GST, and $7,000,000 to rate class GP.

Staff also criticizes the Company's 12+0 updates for not adhering to the Board's approved cost of service methodology. Staff recommends that JCP&L undertake a new cost of service study that fully complies with the Board's pronouncement on the appropriate cost of service methodology as set out in the 1993 Order. In the absence of this information, for purposes of equity, Staff recommends that the distribution-only revenue decrease (after adjustment for the proposed increase of $4.2 million allocated to the lighting class) be distributed on an across-the-board basis to the rest of the classes.

DISCUSSION AND FINDINGS

With regard to allocating the $222.7 million base rate decrease to the various customer classes and developing the appropriate rate design, there is no disagreement that the Average and Excess Methodology (with the excess defined as each customer class's contribution toward the overall system peak) was the preferred method of the Company, Staff and the RPA. However, there was disagreement about certain aspects of the Average and Excess Methodology, all of which focused on the Company's deviation from the Board's policy on the allocation of distribution-related costs.

Absent a cost of service study that fully complies with the Board's most recent findings on the Average and Excess Methodology (with the excess defined as each customer class's contribution toward the overall system peak), Staff recommends that the distribution only revenue decrease (after adjustment for the proposed increase of $4.2 million allocated to the lighting class) be distributed on an across-the-board basis to the rest of the rate classes. The Board reiterates its full support of the Average and Excess Cost of Service Study Methodology as prescribed in JCP&L's 1992 and 1993 Orders and S-22 (which is S-50 from Dkt. ER91121820J) supported by the Board in those cases and **DIRECTS** JCP&L in its next base rate case to fully comply with those orders and submit the appropriate cost of service study.

In the interim, however, in an effort to moderate the impacts to customer classes and for this case only, the Board **HEREBY ADOPTS** the proposed allocation of $79.9 million as reflected in the Company's proposed Settlement and Staff's recommendation to allocate the additional revenue decreases of approximately $142.8 million to the different customers classes, across the board, based upon class proposed settlement distribution revenues. The reduction is apportioned based on each class's percentage of total settlement distribution revenues, excluding GTX, which receives its allocation under GT. For the Lighting Class, which under the Company's proposed Settlement position would have received a rate increase, the Board **HEREBY ORDERS** that the increase be limited to the overall percentage change to the RS Class. For the deferral proceedings, the Board **HEREBY ORDERS** that the increases or decreases be reflected on a usage basis as well as each unbundled non-bypassable charge. For the following interveners who filed specific proposals as to themselves and were signatories to the Company's proposed Settlement, the Board **HEREBY ORDERS** the following:

For Gerdau Ameristeel Sayerville, Inc., (formerly Co-Steel) the Board **HEREBY ADOPTS** the proposed Settlement provisions for Gerdau, effective upon the expiration of Co-Steel's existing contract for service on April 1, 2004. Gerdau will be served as a Service Classification GT customer, subject to all provisions and charges provided for in Service Classification GT, except that (1) the Distribution Charge shall be $1.87 per kw (exclusive of Sales and Use Tax) ("SUT") based only on the actual maximum monthly 60 minute demand for the current billing period, whether on-peak or off-peak; (2) the distribution KVAR and KWH charges shall not be applied, and (3) an MTC credit of $.009844 per kwh shall be applied to all kwh usage.

Regarding the United States Department of Defense/Other Executive Federal Agencies, the Board **HEREBY ADOPTS** the proposed Settlement provision for DOD which provides for a credit against distribution kw and kwh charges calculated to provide an overall reduction in charges to DOD customers that, in the aggregate for all such DOD customers, equals $3.367 million on an annual basis (excluding SUT), based on such customers' 2002 usage, as compared to rates in effect on January 1, 2003, after taking into account the effect of both the lower charges for Service Classification GT and such credit.

For New Jersey Transit, the Board **HEREBY ADOPTS** the proposed Settlement provision to modify GT-Commuter Rail Service Special Provisions so that weekday hours of 5:00 p.m. to 8:00 p.m. shall be considered as off-peak hours for billing purposes. The Board **FURTHER ORDERS** the inclusion of the following language in the Commuter Rail Service Special Provision in the Tariff for Service Classification GT:

> Where traction power is supplied at high voltage (230kv) and such power is being provided during a limited period to supplant power normally supplied by another utility, that limited period shall be excluded for the purpose of determining billing demand.

The Board **APPROVES** the proposed Settlement provision to modify the demand (KW) charge component of the delivery charge to alleviate intra-class customer impact disparities for commercial and industrial customers. Moreover, service classification GST customers shall have an increase in the tariffed monthly customer charge of $11.54 and $16.47 (excluding SUT) for single-phase and three-phase, respectively. All other tariffed monthly customer charges shall remain unchanged.

2. Market Transition Charge ("MTC")

JCP&L

JCP&L proposes to alter the current basis on which its MTC rates were determined. The MTC charge, a transitional charge, was used as a residual for rate design to accommodate the requirement to maintain interclass and intraclass rate neutrality pursuant to the Board's Restructuring Orders. JCP&L proposes to remove the residual effect embedded in the MTC charge for the post-transition period. The MTC charge, as of June 2002, included the Transition Bond Charge ("TBC") and Market Transition Charge Tax ("MTC-Tax") associated with Oyster Creek related stranded costs. The MTC also includes unrecovered BGS costs. JCP&L proposes to adopt an MTC recovery mechanism consistent with the operation of the former LEAC, adjusted for customer voltage for billing purposes. Based on forecasted kWh usage for 2002, the

MTC revenues at the Company's proposed MTC factor adjusted to the voltage level of each rate class totaled $252,978,195, including 6% in Sales and Use Tax ("SUT").

RPA

The RPA opposes JCP&L's proposed MTC rate design, arguing that it substantially increases the burden on residential and general service customers. The RPA asserts that for these customers, the Company's proposal increases their respective MTC revenue responsibilities by 53% and 84%, which is well above the 41% overall MTC revenue increase. The RPA contends that the Board's Final Restructuring Order eliminated the LEAC and that, beginning August 1, 2003, the MTC will no longer recover energy related costs, recovering, instead, only stranded costs, but in a manner different from the recovery of energy costs pursuant to the former LEAC.

The RPA recommends the allocation of future MTC revenues in the same proportion as in the current MTC. The RPA proposes a flat per kWh MTC charge applicable to each rate class based on the total MTC revenues as proposed by JCP&L and its forecasted 2002 kWh usage. The resultant MTC revenue increase to the RS class would be 41% as opposed the Company's 53%, and 40% to the GS class, as opposed the Company's 84%. Hence, the RPA recommends that future MTC revenue burdens be allocated in the same proportion as current MTC responsibility. As such, based on total MTC revenues proposed by the Company and its forecasted kwh usage for 2002, the RPA would apply a flat, per kwh MTC charge applicable to each rate class. The RPA recommended MTC revenue increases for the RS and GS classes are $36,655,013 and $37,224,719, respectively.

Staff

Staff calculated the MTC revenues for each rate class using the RPA's proposed charges. Staff also calculated the RPA's proposed percentage increase/decrease to each rate class using the Company's schedules and the RPA schedules.

Staff agrees with the RPA that JCP&L's proposed LEAC-type mechanism for the recovery of MTC revenues disproportionately affects the RS and GS customer classes. Staff reasons that the MTC was created to recover the above-market cost relating to generation assets in the context of restructuring. To maintain the rate caps during the transition period, however, the Board allowed utilization of the MTC as a residual charge. Staff believes that at the end of the transition period, it will be necessary to separate the various components of the current MTC charge so that energy components will be reflected in BGS, leaving the MTC to recover stranded costs. Staff further believes that the impact of JCP&L's proposed MTC rate design must be weighed against the overall impact from the Board's approved delivery cost of service results and also viewed in the context of previous Board approved mechanisms for recovering such or similar costs and its original treatment of the MTC in the restructuring proceeding.

Board Discussion and Findings

As discussed above, Staff indicated that the impact of JCP&L's proposed MTC rate design must be weighed against the overall impact from the Board's approved delivery cost of service results and also viewed in the context of previous Board approved mechanisms for recovering such or similar costs and its original treatment of the MTC in the restructuring proceeding. The Board in rendering this decision weighs this issue against the impacts to the individual customer classes and previous Board approved MTC rate design mechanisms for recovering such costs. The impacts in the Board's Summary Order and in this Final Order have all reflected this adjustment including the 3.5% impact to the residential class as well as the intra-class impacts resulting from this decision and included in the compliance filing dated July 28, 2003 and approved by the Staff in its September 5, 2003 letter finding the compliance filing to be in compliance with the Summary Order's terms and conditions. Moreover this mechanism is consistent with the voltage specific rate design treatment approved by the Board in its July 31, 2004 decision in the Atlantic City Electric deferral matter.[23] Thus, the Board **HEREBY APPROVES** JCP&L's voltage level adjustments to the individual class MTC charges.

3. Reconnection and Service Charges

JCP&L

JCP&L proposes to increase its reconnection charge for the restoration of service after a service disconnection requested by the customer or because the customer is in default. The current tariff provides for a reconnection charge of $22.00 to customers served under the RS, RT, RGT, GS, and GST tariffs, during normal weekday working hours. During all other times, the reconnection charge is $45.00 for RS, RT, and RGT customers, and $54.00 for GS and GST customers. JCP&L proposes a revised charge of $27.00 for service performed at the meter during normal weekday working hours, and a revised charge of $70.00 for service performed at all other hours to the above-listed service classifications. JCP&L would base all disconnection and reconnection services on actual cost for service classification GP, GSP, and GT. JCP&L also proposes to increase the RS, RT, and RGT service charge from $45.00 to $70.00 and the GS and GST charge for final bill readings performed outside of normal working hours from $54.00 to $70.00.

RPA

The RPA recommends that the current reconnection and service charges remain unchanged. The RPA argues that JCP&L's proposed increase is significantly above the average amount charged by the State's other electric utilities, and is excessive and unduly burdensome to JCP&L's low-income customers. The RPA believes that JCP&L's reconnection charges should be based solely on direct costs that have a linear relationship to the number of reconnections performed without the inclusion of overhead costs.

STAFF

Staff finds the RPA's alternative perspective on the calculation of the reconnection charge compelling and worthy of consideration. It would result however, in a reconnection charge of $16.94 during normal working hours and $44.45 during all other hours, supporting the position to maintain the existing charges. Staff agrees with

[23] I/M/O The Petition of Atlantic City Electric Company D/B/A Conectiv Power Delivery for Approval of Amendments to its Tariff to Provide for an Increase in Rates for Electric Service, BPU Docket No. ER02080510 (July 31, 2004 Summary Order).

maintaining the existing reconnection charges but also turns to recent Board policy on this issue, which consistently established reconnection charges that did not make a distinction between normal business hours and all other hours. Staff recommends that JCP&L only charge the RS, RT, and RGT customer classes a flat fee of $22 for all hours of service restoration. Staff believes that this will soften the impact to those customers who are attempting pay bills in arrears and improve their credit with the Company. Since the Company already has two separate reconnection charges for normal working and all other hours respectively, Staff recommends that the Board maintain the distinction between normal business hours and all other hours for GS and GST customers but continue the existing $54 fee during all other hours.

Staff further recommended that the existing service charges remain at their current level.

Board Discussion and Findings

With regard to Reconnection Charges and Service Charges, the Company proposes in its proposed Settlement to increase reconnection charges from $22.00 to $27.00 during normal business hours (8 a.m. to 4:30 p.m.), and from $54 to $70 at all other hours. The Board **HEREBY REJECTS** this proposal and **HEREBY ORDERS** that JCP&L maintain a flat reconnection fee of $22.00 for all hours of restoration for RS, RT, and RGT classes, and maintain the present rates for GS and GST classes of $22.00 and $54.00 during normal business hours and other hours, respectively. The Board **FURTHER ORDERS** that actual costs shall provide the basis for disconnection and reconnection services for GP and GT classes. The Board **HEREBY REJECTS** JCP&L's proposal to increase existing service charges during other than normal working hours of 8:00 a.m. to 4:30 p.m. Monday through Friday, to $70.00 for all customer classes and **HEREBY ORDERS** that the existing service charges of $54.00 for RS, RT, RGT, GS and GST be continued.

SUMMARY OF BOARD FINDINGS, BASE RATE CASE

Based upon the above, the Board **HEREBY FINDS** the Company's rate base to be $2,016,299,000, its overall allowed rate of return to be 8.38% (including a return on common equity of 9.50%), its operating income requirement to be $168,966,000 and its pro forma operating income at present rates to be $300,436,000 or $131,470,000 more than its operating income requirement. After applying the revenue factor of 1.69398x, the Company's excess revenue requirement is $222.7 million. Accordingly, the Company is **HEREBY DIRECTED** to reduce its base rates by $222.7 million.

V. DEFERRED BALANCES CASE

A. BACKGROUND

1. Sources of BGS Supply

In accordance with the Final Restructuring Order (at 104, paragraph 7), during the first three years of the transition period the Company was to obtain its BGS supply from its owned generating units prior to divestiture, power purchase agreements ("PPAs") with other utilities and non-utility generators ("NUGs"), transition power purchase agreements ("TPPAs")[24] entered into with the purchasers of its divested generating units, and, to the

[24] Sometimes referred to as "parting contracts."

extent these sources were insufficient, a combination of products, including, but not limited to, spot and short-term forward purchases of energy and capacity. The Company was also authorized to employ financial instruments, i.e., hedges, as part of its supply strategy, and while noting that the use of some of these products could reduce ratepayer exposure to price spikes and volatility, the Final Restructuring Order recognized that they could be more costly than relying on the spot market. (Id.)

On October 29, 1998, the Company agreed to sell its fossil units aggregating 1,604 Mw to Sithe Energies, Inc. ("Sithe"), a New York based large independent power producer. In response to the Company's petition filed on February 16, 1999, by Order dated November 4, 1999 ("Sithe Order"),[25] the Board approved the sale, and it closed on November 24, 1999. Under the associated TPPA, the Company could purchase up to the full capacity of the sold units (but not the energy) from November 7, 1999 through May 31, 2002 at "call" rates ranging from approximately $70 per Mw-day to $120 per Mw-day (Sithe Order at 15; S-36)

On October 15, 1998, JCP&L executed an agreement to sell its 25%, 196 Mw interest in TMI-1, a 786 Mw nuclear unit owned jointly with its Pennsylvania affiliates, Pennsylvania Electric Company ("Penelec") (25%) and Metropolitan Edison Company ("Met-Ed") (50%), to AmerGen, a partnership formed by PECO Energy Company and British Energy PLC. The Company petitioned the Board for approval of the sale on December 11, 1998, and by Summary Order dated December 15, 1999 ("TMI-1 Order"),[26] the Board granted its approval and the sale closed on December 20, 1999. Under the terms of the related TPPA, JCP&L began purchasing its share of the unit's energy and capacity on that date for a term extending through December 31, 2001, at bundled energy and capacity prices ranging from approximately $27/Mwh to $30/Mwh. (S-36)

On October 15, 1999, Oyster Creek, a 619 Mw nuclear unit wholly owned by the Company, was also sold to AmerGen. After petitioning the Board on December 13, 1999 and receiving its approval by Summary Order in Docket No. EM99120917 dated July 28, 2000 ("Oyster Creek Order"),[27] the Company closed the sale on August 8, 2000.

---

[25] In Docket No.EM99020067, I/M/O the Verified Petition of Jersey Central Power & Light Company, d/b/a GPU Energy, Seeking (a) Approval of the Sale of Its Non-Nuclear Generation Assets and Certain Additional Real and Personal Property, and the Sublease of Other Certain Interests, Pursuant to N.J.S.A. 48:3-7(b), Specific Determination Allowing the Non-Nuclear Generation Assets of Jersey Central Power & Light Company, Metropolitan Edison Co., Pennsylvania Electric Company to be an Eligible Facility Pursuant to Section 32 of the Public Utility Holding Company Act of 1935 and (c) a Waiver of the Advertising Requirements of N.J.A.C. 14:1-5.6(b). Sithe subsequently sold the units to Reliant Energy. The TPPA was assigned to Reliant, and continued in effect on its original terms.

[26] In Docket No.EM98121409, I/M/O the Verified Petition of Jersey Central Power & Light Company, d/b/a GPU Energy, Seeking Approval of the Sale of the Company's Interest in the Three Mile Island Unit 1 Nuclear Generating Facility Pursuant to N.J.S.A 48:3-7, a Specific Determination Allowing the Three Mile Island Unit 1 Nuclear Generating Facility to be an Eligible Facility Pursuant to Section 32 of the Public Utility Holding Company Act of 1935 and a Waiver of the Advertising Requirements of N.J.A.C. 14:1-5.6(b). A final Order was issued on March 4, 2003.

[27] In Docket No.EM99120917, I/M/O the Verified Petition of Jersey Central Power & Light Company, d/b/a GPU Energy, Seeking Approval of the Sale of the Oyster Creek Nuclear

On that date it began purchasing the energy and capacity from Oyster Creek at bundled prices ranging from approximately \$33/Mwh to \$36/Mwh for a term extending through March 31, 2003. (Oyster Creek Order at 3; S-36)

Prior to divestiture, the energy and capacity of these units was used to supply BGS, and the related costs included as part of the costs recoverable by the revenue received from supplying BGS service[28] to customers choosing not to take service from third party suppliers, as well as the revenue from sales of energy and capacity in the wholesale power market (sales for resale). In addition to fuel, other operation and maintenance ("O&M") expenses, taxes and depreciation, the Company included in BGS recoverable costs a return on its investment in the fossil units and TMI-1 calculated at the pre-tax rate of 14.64%, which it asserts was the return on which its 1996 cost of service study employed in the Board's restructuring proceedings was based. (S-49) The investment on which the return was computed was also taken from the 1996 cost of service study, and was not reduced by monthly depreciation charges during the transition period. Id.

While Oyster Creek fuel, other O&M expenses and taxes were also included as part of BGS recoverable costs, the return on and of Oyster Creek investment (as well as other Oyster Creek sale-related costs) were considered stranded costs, and included as part of the costs recoverable by the MTC. (S-51) The Oyster Creek investment cost recovery was structured to mirror a 13-year securitization via an annuity calculation at 7% interest, and prior to September 2000, was based on net plant investment (gross plant less accumulated depreciation and deferred income taxes) of approximately \$500 million. In September 2000 the investment was reduced to reflect additional deferred taxes estimated to result upon the unit's retirement, or to approximately \$372 million. (S-51)

The balance of the Company's BGS supply during the first three years of the transition period was obtained from long-term, pre-transition PPAs with other utilities and NUGs, short-term forward purchases (bilateral and two-party purchases), and the day ahead and real time spot markets administered by the PJM Interconnection, L.L.C. ("PJM"), now an Independent System Operator ("ISO") and successor to the power pool of the same name. Of these sources, bilateral and two-party purchases were the most significant on a cost basis, comprising as they did almost 40% of the \$3.1 billion total cost of BGS supply during this period, as shown in Exhibit 1 attached to this Order.

In year four of the transition period (the 12 months ended July 31, 2003), the Company's BGS supply was obtained pursuant to the statewide auction approved by the Board by its Order in Docket Nos. EX01050303 et al. dated December 11, 2001.[29]

2. The Phase I Audit Report

Generating Station Pursuant to N.J.S.A. 48:3-7, a Specific Determination Allowing the Oyster Creek Nuclear Generating Station to be an Eligible Facility Pursuant to Section 32 of the Public Utility Holding Company Act of 1935 and a Waiver of the Advertising Requirement of N.J.A.C. 14:1-5.6(b). A final Order was issued on November 21, 2003.

[28] The production cost component of BGS revenue after deducting transmission charges and the 6% New Jersey Sales and Use Tax ("SUT").

[29] Docket Nos. EX01050303, EO01100654, EO01100655, EO01100656 and EO01100657, I/M/O the Provision of Basic Generation Service Pursuant to the Electric Discount and Energy Competition Act, N.J.S.A. 48:3-49 et seq.

As stated in the RFP, the objective of the Board-mandated audits of the deferred balances of the four electric utilities was to "provide the Board with a certified opinion as to whether the Utilities deferred balances as of July 31, 2003 are correct and include only those costs that are reasonable, prudently incurred, accurately calculated, correctly recorded and in compliance with Board Orders." (RFP issued July 29, 2002 at 3) The audits were to be performed in two phases, the first covering the first three years of the transition period (the three years ended July 31, 2002), and the second, the last year of the transition period (the year ended July 31, 2003). For utilities that had divested their generating assets, such as the Company, the audit was to include a prudency review of BGS procurement during the first three years of the transition period, and for all utilities, a review of the utility's efforts to mitigate the above-market cost of power obtained under power purchase agreements with non-utility generators. (Id. at 2-3)

The phase one report for JCP&L was issued in two parts: a *Schedule of Deferred Balances and Attachments For The Three-Year Period Ended July 31, 2002 And Independent Accountants' Report* ("Examination Report"; S-37) prepared by Mitchell & Titus, LLP ("M&T"), and an *Audit of Deferred Balances, Jersey Central Power & Light Company – Phase I* ("Phase I Audit Report"; S-38) issued jointly by M&T and Barrington-Wellesley Group, Inc. ("BWG").

As stated in the Examination Report, M&T's examination of the Company's deferred balances as of July 31, 2002 and related compliance with the Board's Orders was conducted in accordance with the attestation standards established by the American Institute of Certified Public Accountants. Other than finding that the Board's Orders did not address a return on non-nuclear production assets that should be charged against BGS revenue, and that JCP&L did not obtain Board approval for booking $41 million of such return to its deferred BGS balance, M&T stated that "the Company complied, in all material respects, with the Board Orders regarding the deferred balances for Phase 1." (S-37, transmittal letter dated January 7, 2003, page 1) Based on data provided by the Company in its August 1, 2002 deferred balance filing with the Board, the deferred balances examined by M&T aggregated $436.2 million as of July 31, 2002, and consisted of an under-recovered MTC balance of $131.1 million, an over-recovered SBC balance of $12.6 million, an under-recovered BGS balance of $290.6 million, and interest of $27.1 million. (Id., Attachment II)

In addition to providing supporting detail for the Examination Report, the Phase 1 Audit Report included a prudency review of the Company's BGS procurement as well as a review of the Company's efforts to mitigate above-market NUG costs during the first three years of the transition period. M&T's findings and recommendations with respect to the Company's BGS, NNC,[30] SBC and MTC deferrals were covered in Chapters III through VI, and the BGS prudency and NUG mitigation reviews, which were performed by BWG, in Chapters VII and VIII, respectively.

With respect to the MTC deferred balance, the Auditors noted that the Company had incurred additional Oyster Creek costs of approximately $2.5 million not yet reflected in the MTC, and that it had chosen to amortize certain other Oyster Creek costs over 125 months rather than the 132 months (11 years) stated in the Final Restructuring Order.

[30] Non-Utility Generation Charge included in the MTC.

The resultant increase in the deferral, however, was asserted to be immaterial. The Auditors also noted that a pending IRS ruling on accumulated deferred investment tax credits and excess deferred taxes will have an impact on the MTC balance. [31] (S-38 at I-4)

With respect to the BGS deferred balance, the Auditors noted that the 14.64% rate of return JCP&L used in computing the return on its generating assets recoverable by BGS revenue had been applied in the absence of a Board Order[32] specifying the rate or methodology JCP&L should use. (Id.)

In assessing the prudency of the Company's BGS procurement, the Auditors first contrasted the Company's pre- and post-restructuring supply sources. At the beginning of the transition period JCP&L's peak load was 5,180 Mw and its installed capacity was 2,685 Mw. About 31 percent of its energy requirements was supplied by nuclear generation, 10 percent by non-nuclear facilities, and the remaining 59 percent was purchased from other utilities, NUGs and PJM. (Id.)

Following the divestiture of nearly all of its fossil-fueled generating plants (1,604 Mw) and its 25% interest in the TMI-1 (196 Mw) in late 1999, followed by the divestiture of the wholly-owned 619 Mw Oyster Creek nuclear unit in August 2000, the Company retained less than 300 Mw of owned capacity, i.e., its 50% ownership, or 200 Mw, of the Yards Creek pumped storage plant, and 66 Mw of combustion turbines at the Forked River site. For the balance of its post-divestiture BGS supply the Company relied on TPPAs with the purchasers of its fossil-fueled and nuclear generating units, spot purchases from PJM, two-party and bilateral purchases, and PPAs with other utilities and NUGs. During the summers of 2001 and 2002, the TPPAs accounted for about 17% of the cost of the Company's BGS supply, PJM purchases about 15%, two-party and bilateral purchases about 50%, NUGs about 14%, and all other sources, including owned generation, about 4%. (Id. at I-5 to I-6)

While recognizing that one of the objectives of divestiture was to maximize the sale price of the Company's divested assets, the Auditors noted that the TPPAs negotiated by the Company had exposed it and its customers to market price volatility. The lack of an energy contract associated with the fossil sale was also characterized as being "naïve" in view of the unproven nature of the competitive market. Nonetheless, the Auditors observed that the TPPAs had been approved by the Board, as had the divestiture itself. (Id. at I-6)

[31] The Sithe, TMI-1 and Oyster Creek Orders all directed the Company to file for a letter ruling request with the Internal Revenue Service ("IRS") seeking a determination as to whether accumulated investment tax credits and excess deferred income taxes associated with the Company's divested fossil and nuclear generating units should continue to be flowed through to ratepayers on the basis that ratepayers are paying for the units' stranded costs (essentially the Company's booked investment in the units less the proceeds received from their sale). On March 4, 2003, the IRS issued a proposed rulemaking to amend the federal tax code to allow such flow through ratably to cost of service in the amounts permitted under the tax code before the divested units ("deregulated generation property") ceased to be public utility property. Comments on the proposed change were due on June 2, 2003. The IRS has not as yet issued a final rule.

[32] The Auditors did note, however, that a lower rate of return had been authorized for another utility in a Board Order.

The Auditors found JCP&L's strategy for meeting its BGS procurement responsibilities "informed and reasonable," and that the organization established by GPU to perform the procurement "was appropriately staffed to meet planning, procurement and control responsibilities." Moreover, outside consultants were retained to help develop the procurement strategy, planning and management tools, risk management policies and procedures, and employee training. The development of procurement requirements was also actively overseen by GPU management. (Id. at I-6 to I-7)

The same procurement strategies in place for JCP&L were found to have been formulated and implemented for JCP&L's Pennsylvania affiliates as well, and had as their overriding objective minimizing price volatility and the variation in BGS revenue and costs. The strategies were implemented by setting "fill targets" (the amount of on-peak energy to be purchased in a given month) as much as a year in advance, and gradually filling the targets over time with forward contracts, thereby avoiding large purchases at potentially higher prices. (Id.)

The Auditors performed an in-depth analysis of JCP&L's procurement in the high cost summer months of June, July and August of 2001, as well as the months of June and July of 2002, and with the exception of the excess supply assertedly procured for the summer months of 2001, found that JCP&L generally followed its plan for selecting fill targets. As part of this review the Auditors also compared JCP&L's procurement in the summer of 2001 to the provider of last resort ("PLR") procurement of its Pennsylvania affiliates in those months, and concluded that the same methodology for determining fill targets and procurement requirements had been used. Differences between the timing and amounts of the fill targets and related procurements, and thus procurement costs in the two states, were "reasonably attributed to differences in the shopping patterns, customer mix, NUG and utility power purchase contracts and load profiles of the utilities, rather than any attempt to manage costs in Pennsylvania or shift costs from Pennsylvania to New Jersey." (Id. at I-8)

While noting that the FirstEnergy merger may have had a negative effect on the management of BGS procurement activities in the summer of 2001, the Auditors nonetheless concluded that its effect, if any, on costs was negligible. Moreover, JCP&L's retained generation was found to have been reasonably utilized during all three summer peak periods, and not selling Yards Creek, which assertedly reduced the Company's deferred BGS balance by $9 million, at the price offered by PSE&G, the plant's other co-owner, was judged reasonable. On the other hand the Company was found to have made relatively little use of financial and weather hedges that could have provided additional volume protection and potential cost savings during the summers of 2001 and 2002. (Id.)

In reviewing the Company's efforts to mitigate above-market NUG costs the Auditors found that JCP&L had complied with Board requirements as well as the EDECA requirement that it "demonstrate the full market value of the NUG contracts, which was a condition of recovery of NUG contract stranded costs." JCP&L's mitigation program during the first three years of the transition period was evaluated using a list of Preferred Practices developed by BWG, who concluded that in general, JCP&L "had maintained a reasonable and prudent program for NUG mitigation well before the transition period and committed substantial corporate resources to mitigating the costs of its NUG contracts." With respect to the restructuring of the Bayonne contract, however, the Auditors noted that the closing date had been delayed for six months, resulting in a potential loss of savings, and proposed to review this issue, as well as Reliant Energy's offer to restructure JCP&L's NUG contracts that was rejected by the Company, in Phase II. Lastly, the Auditors found that JCP&L had been less than aggressive in mitigating the cost of its smaller NUG contracts (the Camden, Gloucester and Kenilworth PPAs). (Id. at I-9 to I-10)

As indicated above, BWG found that JCP&L had secured too much BGS supply for the summer months of 2001, and in the absence of an adequate explanation for the excess, conservatively estimated that it increased JCP&L's deferred BGS balance by $11.7 million. Should the Board seek a disallowance associated with JCP&L's asserted failure to mitigate the Camden, Gloucester and Kenilworth PPAs, the Auditors suggested reducing the deferred balance by 10 percent of the cost of the purchases under these contracts, or by $5.6 million.[33] (Id. at I-10)

B. THE ISSUES

1. BGS Deferred Balance

(a) Standard of Review

In performing its prudency review of the Company's deferred BGS balance, BWG employed this definition: "Did management make the decisions and take the actions that a reasonable individual would have, given the alternatives and information available at the time such decisions and actions were taken, consistent with legislative and other regulatory requirements?" (Phase 1 Audit Report (S-38) at II-17) This definition, which highlighted the need to judge prudency in light of the alternatives and information available at the time decisions were made, in turn was adopted by Staff and the Company. (Staff's Initial Brief ("SIB") at 123; Company's Initial Brief ("CIB") at 129). Similarly, the Advocate agreed that in evaluating whether the Company acted reasonably and prudently in obtaining its BGS supply during the transition period, its managerial conduct should be judged "in light of the circumstances, information, and options in existence at the time management decisions were made." (RPA's Initial Brief, Vol. 2 ("RIB2") at 2). Citing the Board's Order in the Hope Creek case,[34] the RPA additionally asserted that the burden of proof as to prudency lay with the Company, and accordingly that it must show why its BGS costs were incurred and demonstrate the benefits that were derived from them. (Id. at 2-3) The Advocate additionally urged the Board to review whether the Company had mitigated risk sufficiently. (Id. at 2-3) Interveners Gerdau, DOD and NJ Transit did not address prudency in their Briefs.

(b) Prudency of the Company's BGS Procurement

JCP&L

[33] Corrected to $5.7 million at the hearing on April 28, 3003. (13T 29-2 to 7; Exhibit S-40)

[34] I/M/O the Petition of Public Service Electric and Gas Company for an Increase in Rates and I/M/O the Petition of Public Service Electric and Gas Company for an Increase in Rates – Hope Creek Proceeding, Docket No. ER85121163, Order dated April 6, 1987. At issue were the costs incurred in constructing PSE&G's Hope Creek nuclear plant.

During the period from August 1, 1999 through October 31, 2001, the Company's BGS procurement strategy and costs were supported by Charles A. Mascari, then Vice President – Technical Services for GPU Energy ("GPUE"), the trade name under which JCP&L and its affiliates conducted business prior to the November 7, 2001 merger of their parent company, GPU Inc., with FirstEnergy Corp. of Akron, Ohio ("FirstEnergy merger"). In addition to making supply decisions, the Power Services Division under the direction of Mr. Mascari implemented and administered a voluntary load reduction program with participating commercial and industrial customers, as well as a residential air conditioning and water heating load reduction program. (JC-14 at 8) Following the FirstEnergy merger, the Company's BGS procurement was supported by Dean W. Stathis, JCP&L's Manager of Commodity Sourcing.

Witness Mascari testified that the Company's procurement strategy was based on establishing supply targets related to each future month's forecasted peak load, or more precisely, the "MW equivalent of a percentage of the forecasted BGS load at the time of the PJM monthly peak." (Id. at 7-19 to 7-20) The target was then met by purchasing forward contracts[35] to cover the portion of the target not obtainable from the Company's committed supply (retained generation, TPPAs, pre-transition utility and NUG PPAs), with the difference between the target and the peak load made up by purchases in the PJM spot market. (Id. at 9 to 13)

Based on historical customer usage patterns, the Company developed projected monthly peak loads under assumed normal, mild and severe weather conditions. Also taken into account were trends in customer shopping experienced in Pennsylvania and other states that implemented retail competition prior to New Jersey. With the added input of forward market price volatility, the monthly supply percentages were determined using various mathematical models that "minimize[d] the difference between projected MEC [market energy and capacity] revenues and BGS costs for the range of expected customer usage and market price volatility under the mild, normal and severe weather scenarios." (Id. at 8-13 to 8-23)

On the further assumption that forward and spot market prices would be the same under normal weather conditions, the supply targets varied with changes in the other variables (the mild and severe weather assumptions), and thus the target selected was the one at which the difference in MEC revenues and costs was minimal for both scenarios.[36] (Id. at 9) As Mr. Mascari put it, "JCP&L's objective was to minimize the potential variation in the difference between MEC revenues and BGS costs given the large uncertainties associated with the spot market prices and BGS peak load requirements that were tied to weather variations, especially during the summer and winter." (Id. at 9-1 to 10-5)

Once the targets were established for the remaining months of the current and following year, the Company acquired the supply needed to meet the targets in the forward markets gradually over time, much like the dollar cost averaging ("DCA") employed with stock market purchases, in order to avoid unduly impacting the market in any one month and potentially putting upward pressure on prices. Relying on forward contracts, however, reflecting as they did a risk premium for firm future delivery and prices that

[35] And to a limited extent by the purchase of financial instruments, as shown in Exhibit 1 attached.

[36] Choosing the supply target as the point at which the mild and severe weather curves intersected, as illustrated in Schedule CAM-5 attached to JC-14, was referred to as the "X Method" or model.

could be substantially above the energy and capacity component of the shopping credit, ran the risk of incurring BGS costs well in excess of the cost of spot market purchases should the weather turn out to be mild in the delivery month. While recognizing that "[b]uying forward electric energy contracts was a risk management tool that did not and could not guarantee that spot prices for electric energy would not be lower," the Company nonetheless believed that "leaving JCP&L's customers fully exposed to potentially high electric spot prices, especially during hot summer weather, was an unacceptable and imprudent risk." (Id. at 12-16 to 13-7)

Complicating the procurement problem was the evolving nature of PJM, as it transitioned in April 1997 and April 1998 from an essentially cost-based power pool in which energy prices rarely exceeded $150 per Mwh to a bid-based, two-settlement system, the "day-ahead" market, in which purchases and sales are transacted at fixed prices based on loads and supplies forecast for that day on the previous day, and the "real time" market, in which the forecast versus actual load and supply variances are balanced, and in which prices could go as high as PJM's bid cap of $1,000 per Mwh. (Id. at 14 to 15) Similarly, the market for forward products took time to develop from its initial offering of "5x16 on peak monthly strips," which provided a constant amount of power each hour, 5 weekdays a week, 16 on peak hours a day (7 a.m. to 11 p.m. except holidays), to more diverse energy products ("shaped" products, i.e., products tailored to fit the load profile of the buyer) that could be purchased for periods longer or shorter than one month. Id. PJM's capacity auction market also experienced pronounced volatility as it developed, due at least in part to the high penalties imposed on shortages (double the capacity deficiency rate of $170 per Mw-day when the pool as a whole was short). Lastly, customer shopping did not occur at anywhere near the rate anticipated, peaking at less than 10% of load in April 2000, and, at 7 Mw, constituting about a tenth of a percent of the Company's peak load of 5,266 Mw as of October 2001. (Id. at 14-3 to 23-15; Schedule CAM-4) In concluding his direct testimony, witness Mascari asserted that the Company had "employed prudent strategies to mitigate the cost of purchased power to serve BGS customers, at the time these decisions were made, and in light of the then prevailing market conditions." (Id. at 23-7 to 23-10)

Following the FirstEnergy merger, as directed by the Board in its October 9, 2001 Order in Docket No. EM00110870 approving the merger, JCP&L established a separate organization to procure BGS supply, the Commodity Sourcing Department headed by Company witness Dean W. Stathis. (JC-15 at 4) While the basic objective of the procurement strategy remained unchanged ("minimization of the potential variation in the differences between BGS revenues and costs, given uncertainties in weather, energy market prices and their impacts on BGS load") (Id. at 4-20 to 5-5), the method of filling the supply targets changed from dollar cost averaging to an approach that allowed relatively more forward purchasing if market prices appeared attractive relative to historical norms. (Id. at 15; 4-22 to 5-20) Witness Stathis also noted that prices in the forward market began to decline in February 2001, bottomed out in February 2002, and began to firm again after that. The more flexible post-merger approach of "lock and load," as it was called, was accordingly intended to take advantage of such price declines, and beginning in November 2001, the Company accelerated its forward purchases. (Id. at 9 to11) In contrast, the pre-merger period was generally characterized by rising forward prices. Based on the procurement strategy discussed in his Direct Testimony, witness Stathis averred that the Company's post-merger BGS costs were reasonable and prudent.

RPA

In his Direct Testimony filed on December 20, 2002, the Ratepayer Advocate's witness Paul Chernick was sharply critical of the Company's BGS procurement performance, asserting that the Company "had not demonstrated that it exercised the level of care appropriate for a procurement process of the size of the BGS supply. The Company has not provided any comparison of its expenditures to any measure of market prices, a basic step in demonstrating that it performed well in this important task." (R-59 at 5-8 to 5-12) As discussed more fully in the section, *Pennsylvania vs. New Jersey Supply Costs* below, the only cost comparison then in the record, that between the prices the Company paid for its non-NUG, non-TPPA purchases as compared to the prices its Pennsylvania affiliates paid, showed that the Company paid about 13% more than they did, which translated into an increase of $239 million in the cost of its BGS supply during the first three years of the transition period. (Id. at 5-12 to 5-17; Schedule PLC-2)

The Company's alleged failure to document its decisions regarding BGS procurement in turn assertedly made it "impossible for the Board to find that JCP&L was prudent in selecting objectives, and executing the actions selected in the planning process. The lack of retrospective reports and analyses of JCP&L's decisions also directly raises questions about prudence, since frequent reports would be necessary to evaluate performance in this novel environment." (Id. at 7-2 to 7-7) Additionally, the Company's basis for determining how much energy to purchase in the forward markets was found to be flawed: rather than trying to minimize monthly variation in earnings, witness Chernick asserted, the Company should have been "attempting to minimize the cost of BGS supply for ratepayers." (Id. at 7-8 to 11)

After emphasizing how important extensive documentation of procedures, decisions and outcomes was in view of the magnitude of the Company's BGS financial commitment ("over $3 billion, comparable to the cost of a nuclear power plant"), and after outlining the detailed data he expected the Company would have routinely kept for each purchase it made, Mr. Chernick asserted that to evaluate how well the Company performed in minimizing the cost of BGS supply from a process standpoint, the Board could examine 1) whether the attributes he recommended had been included in the Company's planning and procurement process; 2) whether the Company followed its own rules and guidelines; and 3) whether its decisions were reasonable. (Id. at 11 to 16) From a results standpoint, the prices the Company paid for its BGS supply could be compared to appropriate benchmarks, including procurement by other utilities and various market indices. (Id. at 15-21 to 16-6) The Company was found wanting on all counts. (Id. at 16-25)

Mr. Chernick also critiqued the Company's models, finding, as noted above, that the objective on which they were based, minimizing the difference between BGS costs and revenues (or as it was described elsewhere by the Company, minimizing "variations in energy supply Pre-Tax Earnings due to weather") was inappropriate. (Id. at 26) Moreover, such an objective could yield the perverse result of increasing BGS costs when they were less than BGS revenues.[37] Id. He went on to discuss the so-called "X method," the spreadsheet model described in witness Mascari's Direct Testimony (JC-14 at 8-13 to 11-7) and illustrated in Schedule CAM-5 attached to that testimony. (R-59 at 26 to 27) As compared to minimizing customer costs, witness Chernick again found the

[37] Although Mr. Chernick doubted that JCP&L would intentionally increase BGS costs to bring them closer to MEC revenues, he cited that possibility to illustrate the "irrelevance of the Company's stated objective." (R-59 at 26, footnote 9)

use of this model to determine the level of forward contracts that would produce the same after-tax earnings to the Company under two arbitrarily chosen weather conditions to be misguided. Id. He also found the HOST[38] model, which replaced the X-model in February 2001, to be inadequately explained, and that the monthly "fill" rates it prescribed (5% of the target per month until the target was met two months prior to the delivery date) were in any event disregarded by the Company. (Id. at 26-17 to 28-7, including the footnote on page 27) Moreover, the targets prescribed by either model were found to have varied erratically over time, and with the advent of the accelerated purchasing strategy following the merger (the lock and load strategy), several examples of overshooting or undershooting the targets were cited, and plotted in Schedule PLC-4, in which Mr. Chernick compared the actual to the targeted fill rates for the months of December 2001 through July 2002. (Id., Schedule PLC-4) Moreover, in an apparent inconsistency, the historical norms on which the Company based its accelerated purchasing decisions turned out to be the average actual PJM on peak prices over the three-year period 1998 through 2001, rather than the forward prices asserted by the Company. (Id. at 29-8 to 29-17)

Mr. Chernick also cited several examples of the Company's failure to provide after-the-fact comparisons of its costs of purchasing BGS supply to other measures of costs, including the Company's response to a discovery request[39] in which it refused to compare the costs of its congestion hedges to the actual cost of congestion on the grounds that "an after the fact comparison such as is requested has no relevance in determining whether or not the acquisition of a hedge was an appropriate action at the time such acquisition was made." (Id. at 31) Similarly, in its response to another discovery request,[40] the Company stated that it had not analyzed whether the post-merger acceleration of its forward purchases had reduced the cost of BGS supply relative to the pre-merger strategy because it did not believe "such after-the-fact analyses were relevant because the prudence of the actions must be judged in light of the facts and circumstances as they existed at the time the decision was made and cannot be reassessed with 20/20 hindsight." (Id. at 30-23 to 31-12)

Moreover, Mr. Chernick asserted that the Company did not even retain information that would permit a before-the-fact prudency review of its purchasing decisions. (Id. at 31 to 32) In responding to yet another discovery request,[41] for example, the Company stated that it did not save the market price data it received from brokers at the time it made its purchase decisions because such data served no further "operational" purpose. (Id. at 31) Neither did the Company save the price quotes it received when it made market sales. Id. Nor did it document the capacity offers, market intelligence, notes of discussions with counterparties, or the conclusions and decisions it made based on this information. Id. Additionally, because it apparently didn't perform any after-the-fact analyses as it went along, there was no way of assessing the effectiveness of the Company's procurement decisions:

[38] The acronym for "Hedge Optimization Strategy Tool."

[39] RAR-BGS-132.

[40] RAR-BGS-127.

[41] RAR-BGS-12(a).

> It is true that the outcome of any one decision, out of many, does not determine whether it was "an appropriate action at the time such acquisition decision was made." Good decisions sometimes have bad outcomes. But JCP&L should have been conducting after-the-fact comparisons throughout the BGS procurement period to guide its procurement. Furthermore, Your Honor and the Board need to see the results of after-the-fact comparisons today.
>
> The Company should have been conducting after-the-fact comparisons throughout the BGS-procurement period because information on the performance of a strategy is vital to determination of whether the strategy should be continued. If every transaction of a particular type that JCP&L made turned out to be uneconomic, prudent management would require that the use of that type of transaction be re-examined, restricted, or stopped entirely. I do not believe that JCP&L could prudently acquire BGS supply without such information.
>
> [Id. at 32-3 to 16]

Finally, Mr. Chernick asserted that the Company had not shown that it had managed its load control and demand-response programs in a way to minimize BGS costs.[42] (Id. at 33-3 to 33-12)

JCP&L's Rebuttal

In Rebuttal Testimony filed on January 24, 2003, Mr. Mascari disputed Mr. Chernick's assertion that the Company had not demonstrated that it had exercised the level of care appropriate for a procurement process the size of its BGS supply. As evidence, he included in his testimony a copy of a presentation the Company made to the Board's Staff and the Ratepayer Advocate in April 2000 that described the Company's procurement strategy, the processes and organization it established to implement the strategy, its Risk Management Position Tracking System, and the inputs and outputs produced to provide an audit trail of the Company's procurement actions. (JC-14 Rebuttal at 8-3 to 8-12; Schedule CAM-13) Moreover, the Company's employees and management involved in making purchasing decisions, executing transactions, or developing marketing models or otherwise involved in BGS procurement, underwent extensive training to obtain the new skills demanded by the competitive marketplace as early as 1997, when it became clear that retail choice would be

[42] Mr. Chernick also took the Company to task for not providing the data necessary for the other parties to conduct comparative reviews of its BGS costs and not providing timely responses to the Advocate's discovery requests (R-59 at 5-18 to 24; 17-1 to 19; Schedule PLC-3). Staff, however, attributed the delay more to the volume of requests the Company received rather than to any intent on its part to be unresponsive. Having said that, Staff also pointed out that the reasonableness of the Company's performance could only be assessed by looking at unit costs (the cost per Mwh of energy and per Mw-day of capacity produced or purchased), and that this all-important data was generally lacking in the Company's filing.

implemented in both Pennsylvania and New Jersey. (Id. at 9 to 11) As an example, the Company cited the Princeton Energy Programme, a classroom-based program that provided 80 hours of instruction in energy risk management and financial instruments to key employees. Teknecon Energy Risk Advisors, Inc. ("Teknecon") was also retained to assist in the development of risk control policies and procedures, and to provide guidance to the GPU Risk Oversight Committee ("ROC"), the organizational entity charged with setting and monitoring the GPU System's risk policies and procedures. Morgan Stanley Capital Group and the Brattle Group were also retained to assist in the development of hedging strategies and a "position tracking" software system. (Id. at 9-10 to 12-15)

Mr. Mascari also discussed the sources of data the Company relied upon to insure that its purchases in bilateral markets[43] were made at no more than market prices, including NYMEX, PJM and ECAR market data, Platts' Power Market Week, and real time quotes from Morgan Stanley Capital. (Id. at 14 to 17) The Company also had standing agreements in place for executing physical purchases and sales with a wide variety of firms, as well as for purchasing financial instruments. Evaluating the latter was aided by software tools @RISK and @ENERGY.[44] (Id. at 14-3 to 16-7)

Discretion and the flexibility to respond to changing circumstances, particularly in the aftermath of the California energy crises in mid-2000 and when prices began to fall in the post-merger period, were said to have accounted for the variations in fill and target rates Mr. Chernick inaccurately characterized as being "erratic." (Id. at 19-13 to 22-5)

In defending the Company's objective of minimizing variation in the difference between BGS costs and revenues, Mr. Mascari asserted that, by taking into account a wider range of uncertainties, this objective was superior to Mr. Chernick's simplistic "minimize cost" approach. (Id. at 22-6 to 23-4) In summary, in finding Mr. Chernick's concerns baseless, Mr. Mascari asserted that:

? JCP&L's divestiture of its generation assets and procurement of full output TPPAs for its nuclear plants and capacity options for its fossil plants was consistent with Board policy and reasonable assessments of its ongoing needs, and was approved by the Board.[45]

? JCP&L approached the BGS procurement process with the highest level of care, including extensive training of responsible personnel and use of expert consultants.

? JCP&L had the same incentives to control BGS costs as its Pennsylvania affiliates, because of the known risks of this prudence review, and the Company and its Pennsylvania affiliates employed the same fundamental procurement strategies, so that any differences in outcomes were the

[43] Markets not formally organized as exchanges.

[44] An additional model, Nostradamus, described by its vendors as a "short-term, neural network-based demand and price forecasting system," was also apparently used to assist in preparing short-term forecasts. (R-59 at 26-22 to 23)

[45] In his Direct Testimony (R-59), Mr. Chernick had faulted the Company for not obtaining energy as well as capacity in negotiating the TPPA for the fossil units with Sithe.

result of differences in the underlying markets and customer base in the two states.

? JCP&L's processes and procedures for BGS procurement ensured that all purchases of relevant products were effected at then-prevailing market prices for the product in question at the time of purchase.

? JCP&L has provided extensive amounts of data in this proceeding that support all aspects of its BGS procurement process.

? JCP&L's implementation of its BGS procurement processes was consistent with its strategies and plans, as the use of rigid fill formulas would not have been prudent, and any alleged deviations from the strategy have been explained by external events.

? JCP&L's objective to minimize variances and risks was appropriate.

? JCP&L has pursued an active and aggressive NUG mitigation program.

? JCP&L made appropriate use of its load-control and demand response programs to mitigate BGS costs.

[Id. at 26-1 to 27-14]

With respect to the post-merger period Mr. Stathis challenged Mr. Chernick's assertions that the Company lacked a coherent post-merger strategy and that it had not demonstrated that its load-control and demand-response programs were effectively managed to reduce BGS costs. (JC-15 Rebuttal) As to the first assertion, Mr. Stathis explained the Company's post-merger strategy as follows:

> JCP&L had in place a procurement strategy that was based upon triggering additional purchases above and beyond minimum targeted levels when forward prices dropped to the level of JCP&L's estimates of the marginal cost of production and thus were unlikely to fall much lower. This decision to accelerate short- and long-term procurements for the post-merger time period of November 2001 through June 2002 was an outgrowth of a study undertaken in the summer 2001 and dubbed the "Lock & Load" study. This research had identified PJM on-peak forward electricity price levels that were approximately equal to JCP&L's estimates of the marginal cost of producing electricity in the PJM region. When the merger closed in early November 2001, the "Lock & Load" price triggers were discussed with FirstEnergy management, who recommended implementing a price trigger range based upon three-year averages of actual average monthly on-peak prices and the "Lock & Load" values [shown in Schedule DWS-6]. JCP&L reviewed and

> accepted this Recommendation. This range was the basis for 58 on-peak forward purchases totaling 3400 MW [shown in Schedule DWS-7]. Thus, the post-Merger procurement strategy had a definite justification.
>
> [Id. at 2-2 to 2-22]

As shown in Schedule DWS-6 attached to JC-15 Rebuttal, the prices that would trigger lock and load advance purchases of on-peak energy for the target months of December 2001 through June 2002 varied from a low of $29.37 per Mwh to a high of $35.35, and with few exceptions were adhered to in making the 3,400 Mw of forward purchases shown in Schedule DWS-7.

Given that the HOST model was no longer used in setting monthly supply targets after the merger (the targets simply became the average peak load forecast for the target month), Mr. Stathis asserted that the data on which Mr. Chernick's Schedule PLC-4 was based was incorrect, and thus that this schedule did not accurately portray the variance between the actual and targeted fill rates. (Id. at 3-18 to 4-3)

In response to Mr. Chernick's assertion that the Company's load-control and demand-response programs had not been shown to have reduced BGS costs, witness Stathis pointed out that the "PowerPlus Savers Program," a water heating and air conditioning load reduction program for residential customers in which more than 74,000 customers were participating by 2002, achieved a total load reduction of 62 Mw in 2002. (Id. at 5-6) While no estimate of the cost reduction achieved by the Power Plus program was provided, Mr. Stathis estimated that the Company's Voluntary Load Reduction Program, in which 40 commercial and industrial customers participated, reduced its deferrals by $1.1 million through 2002, and its peak load by 45.5 Mw. (Id. at 5-1 to 6-16)

In refuting Mr. Chernik's assertion that minimizing the difference between BGS costs and revenues was not an appropriate objective of the Company's target-setting models, the Company also presented the testimony of Frank C. Graves, a Principal with the Brattle Group, a Massachusetts-based firm that provides consulting services to the electric power and natural gas industries. In Rebuttal Testimony filed on January 24, 2003, Mr. Graves identified the appropriate goals of a prudent supply strategy as being "1) the procurement of firm, reliable supply for the BGS net load at prices prevailing in the competitive wholesale markets, 2) the reduction of the *ex ante* (*i.e*., before-the-fact) volatility risk of BGS procurement costs, and 3) the avoidance of exposure to transient, adverse market conditions." (JC-19 Rebuttal at 18-4 to 18-14)

Given that market prices are not within the Company's control, the goal of supply procurement becomes one of reducing volatility (risk management), which, while not materially changing expected costs, does protect against extreme outcomes. "As such, it should be judged on its ability to control variation around the expected market costs of procurement, rather than variation around BGS rates or revenues." (Id. at 19-15 to 20-6)

To illustrate his point, witness Graves presented a graph (Exhibit FCG-6 on page 6 of JC-19 Rebuttal) comparing the probability distribution of the possible costs of a strategy under which forward power to meet the supply requirement of a future delivery month is purchased gradually over time, to one that relies exclusively on spot market purchases in that month. While the mean, or expected cost of the two strategies is assertedly the same, Mr. Graves observed that the range of potential variation is much greater for the spot market strategy. The curves also showed that while there is a higher probability of experiencing costs lower than the mean under the spot strategy, the probability of experiencing increased costs is also higher. However, due to the "skewness" of the spot market cost distribution, the amount by which the higher spot market cost is likely to exceed the mean is greater than the amount by which it is likely to be less, and accordingly this should be taken into account in deciding upon a forward purchasing strategy.

As to managing "procurement to the BGS rate itself," i.e., eliminating the deferral entirely, that is not feasible due to the fact that wholesale prices exceeded the capped BGS rate during the transition period, and thus the purpose of risk management was to ensure that the actual under-recovery did not deviate very far from the expected under-recovery. (Id. at 20-7 to 21-2; 24-19 to 25-1)

In describing the Company's models and how they evolved, Mr. Graves began with the X-Method employed by the Company until February 2001, when it was replaced by the HOST model. (Id. at 32) Using the month of July as an example, Mr. Graves showed how the difference between the Company's projected BGS costs and revenue ("Pre-Tax Earnings Equivalent") varied under mild and severe weather conditions. On the assumption that forward prices reflect normal weather conditions, purchasing increasing amount of forwards will result in reduced costs if the weather turns out to be severe, since the spot price would then be expected to be higher than the forward price. (Id. at 33) Conversely, purchasing lesser amounts of forwards will result in reduced costs if the weather turns out to be mild, because the spot price would be expected to be less than the forward price in this case. Id. The point where the upward sloping severe weather curve intersected the downward sloping mild weather curve was chosen as the supply target (the percentage of the July load that was to be supplied by forwards). As shown by the graph illustrating the method (JC-19 Rebuttal, FCG-9 on p. 33), the target for July appeared to be somewhat greater than 100%. (Id. at 32-8 to 33-15)

Turning to the Host model, witness Graves noted that while it was conceptually similar to the X-Method, it incorporated a number of enhancements, including the ability to model "more numerous and complex scenarios, more hedging instruments, greater use of market information about the relationship between forward and spot prices, correlation between load and price, and a more formal measure of risk. [46] Specifically, it expands the scenario set from two basic weather scenarios (mild and severe) to a continuous price probability distribution spanning many load conditions. In addition, it calculates an optimal hedging strategy based on the use of forwards and options (monthly over-the-counter call options for on-peak forwards) as hedging instruments, rather than just forwards." (Id. at 34-1 to 34-13)

In finding both models to be appropriate tools in managing JCP&L's BGS risk, witness Graves also found the supply targets set by their use to have been reasonable, and not to have changed arbitrarily as contended by Mr. Chernick. The single instance in which a

[46] The "certainty equivalent" of net cash flows, which was asserted to be "a well known and commonly used technique to effectively value different distributions of outcomes by placing a dollar value on the variance (based in this case on JCP&L's risk tolerance level), thereby allowing for direct dollar-to-dollar comparisons across different procurement strategies." (JC-19 Rebuttal at 30-10 to 18, including the footnote) The JCP&L reference was to its management, not its ratepayers.

substantial shift in the X-Method targets occurred, that between January 3 and January 17, 2000, Mr. Graves attributed to the realization that customer switching to third party suppliers was not going to occur to the extent previously assumed. Similarly, the declining supply targets set by the HOST model were explainable by the declining forward prices that occurred in 2001 and 2002. Finally, in countering Mr. Chernick's apparent belief that off-peak as well as on-peak hours should have been hedged, Mr. Graves cited the much greater price risk exposure associated with on-peak energy and the limited availability of off-peak forwards and options. (Id. at 35-3 to 39-11)

In concluding his testimony, Mr. Graves noted that of the approximate $3 billion of power resource costs JCP&L managed during the transition period, about $1.6 billion took the form of open market purchases, and that:

> Of this procurement, essentially none of it had controllable costs, and only some of it had controllable risks. For instance, the costs of intra-month spot balancing were essentially unhedgeable, as were the costs of PJM charges such as ancillary services. The total amount of BGS load that had to be served was initially highly uncertain, because of the unfulfilled expectation that there would be a significant shift toward retail suppliers. But even without that occurring, the market-procured component was a volatile, complex, peaky, weather-sensitive residual shape that was ill-suited to being covered by standard, relatively flat wholesale contracts. The PJM market itself was in a state of developmental flux, including some occasional doubts about the quality of its competition, to which JCP&L was particularly vulnerable.
>
> In this extremely complex environment – far more difficult to evaluate than most mature commodity markets such as currencies or interest rates that are usually deemed quite complex – JCP&L developed a series of sophisticated models that it monitored and updated regularly. While relying on those models for formal measures of risk, JCP&L also exercised a great deal of careful but difficult out-of-model judgment about the quality of market performance it was facing. Under the circumstances, I think this is successful, prudent decision-making that should not involve any disallowances.
>
> [Id. at 40-1 to 41-3]

Auditors' Findings

In reviewing the prudency of the Company's BGS procurement, the Auditors found that the Company "had not provided an adequate explanation for deviating from its BGS fill strategy and exceeding hedge target procurement levels for the summer of 2001 during the months of January through March of 2001." (Phase 1 Audit Report (S-38) at I-10; VII-36) Based on an analysis of the Company's forward procurement for the months of June, July and

August 2001 (Id. at VII-37 to VII-42), and the quantification shown in Exhibits VII-20, 21 and 22 and explained on pages VII-57 through VII-59, the Auditors recommended that the Company's BGS deferred balance be reduced by $11.7 million to eliminate these "excess and unnecessary costs." (Id. at VII-36) While the Auditors performed a similar analysis of the Company's forward purchases for the months of July and August 2002, they proposed no disallowance for these months. (Id. at VII-43 to VII-44)

Staff's Position

Staff agreed with witness Chernick's criticism of the models employed by the Company, as well as his contention that they were inconsistently applied in securing BGS supply during the first three years of the transition period. In particular, Staff found the objective that drove both the X-Method and HOST models, minimizing the difference between BGS costs and revenues, i.e., minimizing the effect on the Company's earnings, to have been misguided and inappropriate. While such an objective may have had some justification in obtaining the provider of last resort supply for the Company's affiliates in Pennsylvania, it clearly had none in New Jersey, where if anything, the Company realized an earnings *benefit* from its deferred balances by virtue of what, in retrospect, was a generous carrying cost allowance, the yield on 7-year constant maturity treasury notes plus 60 basis points, on the deferred balances during the transition period.

While noting that if costs were less than revenues, minimizing their difference could actually increase BGS costs, Mr. Chernick did not suggest that this result actually occurred. However, Staff was less sanguine, asserting that one could not be certain that this objective of the Company's models (the HOST model in particular[47]) could not, or did not produce this perverse result. Nor in Staff's judgment was this issue ever satisfactorily addressed by the Company.

Moreover, this choice of the models' objective appeared to Staff to permit outright speculation, or purchasing energy in excess of the Company's requirements. Given that under normal circumstances energy costs per kwh will always be higher than the annual average in the peak summer months (July and August, typically),[48] the only possible way the difference between BGS revenue from sales priced at the fixed annual average (the shopping credit) and the costs incurred in these months could be minimized is through buying forward contracts in excess of load,[49] and re-selling the excess energy at a profit – an extremely risky strategy in Staff's view, in that it exposes the utility to potentially

[47] As indicated in Attachment RAR-BGS-48(3) included in Exhibit R-56, the inner workings of the HOST model are so abstruse as to have made it impractical, if not impossible to tell in this proceeding if, how, or under what circumstances this result could occur.

[48] This is attributable to the economics of supplying load that varies seasonally, i.e., low capital cost, high fuel cost generating units (single-cycle CTs) are installed for the express purpose of economically serving seasonal (peak) demand.

[49] See, for example, the graph on page 12 of Attachment RAR-BGS-211(5) included in Exhibit R-51, which indicates that the hedge target that minimized the variance in the total cost of BGS supply in the delivery month of July 2000 was 124% of gross load (load not reduced by committed supply). On a net basis after deducting committed supply, the target was 151%, as indicated on page 15 of Attachment RAR-BGS-211(5). While the graph portrays the variance in cost, under the assumption of fixed BGS revenue, minimizing the variance in cost would also presumably minimize the variance in the difference between the revenue and the costs.

large losses if the excess energy has to be resold at a loss.[50] Moreover, this appears to have been exactly what happened in the months of June and July 2000.

In a series of presentations the Brattle Group made to GPUE in the fall of 2000 in support of its recommended dollar cost averaging,[51] and while the purpose of the presentations was to compare the recommended DCA approach to the Company's BGS procurement strategy in use at that time, the Brattle Group did, in fact, perform a retrospective analysis of how JCP&L's actual BGS procurement results compared to both the DCA approach and 100% reliance on the PJM spot market during the period from December 1999 through July 2000. As shown on page 7 of the November 29, 2000 presentation (and repeated on page 31), under the Brattle Group's proposed DCA hedging method, the *ex-post* (after-the-fact) cost of on-peak energy purchased during the 8-month period would have been $136.4 million, as compared to the $148.4 million actually incurred under GPU's strategy. If all of the energy had been purchased in the spot market, its cost would have been $66.4 million – less than half the cost of the energy purchased under either the Company's or the DCA approach recommended by the Brattle Group. However, rather than analyzing the reasons for the $82 million difference between the actual cost of the purchases and what their cost would have been if they had been made in the spot market,[52] the Brattle Group devoted several pages of the presentation to explaining the reasons for the relatively insignificant $12 million difference between the two hedging methods. (R-51, Attachment RAR-BGS-211(4) at 31-34)

In analyzing the data included in the Appendix attached to the November 29, 2000 presentation (Id. at 42), Staff found that purchasing about 50% more forward on-peak energy than the Company needed in the months of June and July 2000 accounted for $53 million of the $82 million of excessive costs it incurred during the 8-month period analyzed. In June, the Company purchased 469 Gwh in excess of its on peak energy requirements at an average cost of $63.54 per Mwh, and resold this energy in the spot market for $33.18, incurring a loss of $14.3 million. In July, the Company purchased 482 Gwh more than it needed at an average cost of $114.02 per Mwh and resold it for $33.51 per Mwh, incurring a loss of $38.8 million. Thus, excess purchases in these two months alone accounted for nearly 65% of the total excessive cost incurred above spot. In Staff's view, the $53.1 million excessive cost, arising as it did from speculative forward purchases, should under no circumstances be recoverable from ratepayers. That the Company or its consultants did not perform this simple analysis, nor in view of the $82 million total cost differential question the cost-effectiveness of the Company's procurement method at that time, Staff found to have been patently imprudent.

---

[50] In confirming that the supply targets could be greater than the expected load in the summer months, Mr. Graves defended this by asserting that "being short of MWs in a tight market can be more costly than being long that same number of MWs in a soft market." (JC-19 Rebuttal, 35-21 to 36-3)

[51] Dated September 19, 2000, November 29, 2000 and December 20, 2000, copies of which are included in Exhibit R-51 (Attachments RAR-BGS-211(3), (4) and (5), respectively).

[52] In a similar presentation dated December 20, 2000 (Attachment RAR-BGS-211(5) included in R-51), in which the same retrospective cost comparison was included, the Brattle Group dismissed the $82 million difference by attributing it to a cool summer: "Ex post, an all-spot (no hedge) strategy happens to have a low cost, due to unusually cool weather in Summer '00. It would be very speculative, and potentially dangerously costly, to rely on such events occurring."

Given the sheer magnitude of the difference, Staff maintained that a reasonable person would have concluded that under its procurement method, the Company was both purchasing more forward energy than it needed and paying far too much for it, and thus should have examined less costly alternatives at that time (the fall of 2000), about half-way through the first three years of the transition period when a change in the Company's procurement method could have made a meaningful difference in the costs incurred during the balance of the period.

As to the first issue, purchasing too much energy, setting hedge targets simply defines how much energy is to be contracted for in advance, and how much is to be obtained from the spot market. Given the unpredictability of estimating what the future cost of energy might be,[53] one simple alternative to the Company's approach cited by Staff as an example would be to, at most, be only "half wrong" by purchasing 50% of the delivery month's uncommitted supply forward, subject to a price constraint, and relying on the spot market for the other half. By limiting forward purchases to 50% of the supply requirement, speculative purchases (purchases in excess of the energy needed) would be eliminated.

As to the second issue, paying too much, Staff pointed out that the Company had a long history of purchasing very large quantities of interchange energy from PJM, and thus had to have known that what it was paying for forward energy was far in excess of the cost of its historical purchases. Rather than paying any price in a market that was much more illiquid than the PJM spot market, Staff asserted that the Company should have established a threshold for the forward risk premium above historical cost beyond which it would not go (5%, for example),[54] and place correspondingly greater reliance on the spot market, i.e., for up to all of its requirements if forward prices exceeded the threshold, again on the basis that the Company was unlikely to do any worse than if it had contracted for the forward purchases at prices greater than the threshold.[55]

While noting that more sophisticated alternative procurement methods could undoubtedly have been examined, Staff's point was that in the face of what Staff considered to be clear evidence that the Company was on the wrong track as early as September 2000,[56] it and its consultants nevertheless chose not to explore potentially better alternatives, but also committed further to a flawed and inappropriate purchasing strategy by adopting the simplistic and only modestly effective enhancement of dollar

---

[53] For all the reasons outlined above by the Company.

[54] As compared to an average premium of approximately 23% estimated for the transition period by comparing the average forward on-peak price ($46.76 per Mwh) calculated from Mr. Graves' Revised Exhibit FCG-8, to the average on-peak spot price calculated from that exhibit ($37.95 per Mwh). One possible explanation suggested by Staff for this high premium is that in addition to the time-related component, it reflects at least some allowance for severe (hotter than normal) weather, contrary to the Company's assumption of normal weather.

[55] Staff considered the "lock and load" strategy to be *de facto*, albeit belated, recognition on the Company's part that a purchasing strategy linked to historical cost was the better way to go.

[56] The month in which the first Brattle Group presentation that contained the retrospective analysis discussed above was made.

cost averaging. Staff found that to have been clearly imprudent, and recommended that $152.5 million of the Company's deferred BGS balance be disallowed.

In quantifying its recommended disallowance, Staff compared the cost of the Company's "discretionary purchases" (defined below) to the substantially lower cost of purchasing the same energy and capacity from PJM. Credited against this difference were cost benefits achieved from the Company's TPPAs, also as compared to purchasing the same energy and capacity from PJM, as well as savings achieved from renegotiating the PPA with the Bayonne NUG project. While based on data supplied by the Company, this analysis was similar to the "benchmark" analysis included in the Phase 1 Audit Report at Staff's request (Appendix B).

As indicated by Mr. Laros of Barrington Wellesley at the hearing on April 28, 2003, one of the uses of retrospective analyses of the type Staff requested is the quantification of the impact of a finding of imprudence. (13T 80-5 to 80-10)[57] However, rather than relying on Appendix B for this purpose, Staff used the more detailed data (the data on capacity purchases as well as energy purchases) included in Exhibit S-32, the Company's response to a discovery request[58] in which the Company was requested to perform the same analysis shown in Appendix B of the Audit Report. In both instances the data was supplied by the Company, and while there are slight differences between the two, they are not significant, as indicated below:

TABLE 1

JERSEY CENTRAL POWER & LIGHT COMPANY

Actual Cost of Non-TPPA Discretionary Purchases * as Compared to the Cost if Purchased from PJM, 3 Years Ended July 31, 2002
Appendix B of the Audit Report vs. Exhibit S-32
($ Millions)

	Gwh Purchased	Actual Cost	PJM Cost	Increased Cost, Actual over PJM $ Millions	%
Appendix B	18,711	$1,119	$793	$326	41.1%
Exhibit S-32 **	18,735	1,125	796	329	41.3%

* purchases other than those made under TPPAs and pre-transition PPAs with other utilities and NUGs, i.e., the combination of two-party, bilateral and PJM purchases made by the Company in carrying out its BGS procurement strategy.

** priced at the weighted average PJM "sink bus" LMP and capacity market rates.

[57] Subject to possible adjustment to reflect the factors discussed on the preceding page of the transcript.

[58] S-JBGS-1

Similarly, on a unit cost basis there is no significant difference between the two analyses (about $60 per Mwh for the actual purchases as compared to $42 per Mwh if the same energy and capacity had been purchased from PJM). Thus both analyses show that if the Company had relied on the default option of PJM for all of its non-TPPA discretionary purchases during the first three years of the transition period, its BGS procurement costs would have been approximately $330 million lower.

On the other hand, the Company did much better in negotiating its TPPAs with AmerGen for the post-sale purchase of the energy and capacity of TMI-1 and Oyster Creek. As shown and derived in Exhibit 2 attached, Staff estimated that during the first three years of the transition period, the Oyster Creek TPPA purchases reduced the Company's BGS procurement costs by about $64.2 million as compared to equivalent purchases of energy and capacity from PJM, and that the TMI-1 TPPA purchases reduced the Company's BGS costs by an additional $46.0 million. On a unit cost basis, the average cost of Oyster Creek TPPA purchases, at $35.29 per Mwh, was about 16% less than the estimated $41.90 per Mwh average price of PJM energy and capacity that would otherwise have been paid for the equivalent PJM purchases during the portion of the term of the Oyster Creek TPPA that fell within the first three years of the transition period (August 8, 2001 through July 31, 2002). The reduction estimated for the TMI-1 TPPA purchases is even greater: $27.52 per Mwh, as compared to $41.86 for purchasing the equivalent PJM energy and capacity over the term of the TMI-1 TPPA (December 20, 1999 through December 31, 2001), a reduction of over 34%. Moreover, in addition to the favorable pricing, the relatively long terms of the TPPAs (two years for the TMI-1 TPPA and 2 years plus an additional 8 months for the Oyster Creek TPPA, during which Staff estimates the Company realized an additional $28.1 million of savings) were clearly beneficial.

Based on the Company's projections, there will also be annual benefits from the "Deal Strike Price Adjustment" component of the TMI-1 TPPA[59] through the year 2010, of which the Company estimates its 25% share will be $12.8 million on an NPV basis. (S-53)

As indicated in Exhibit 2, Staff performed a similar analysis to assess the cost-effectiveness of the capacity-only Sithe TPPA, but found that the related capacity purchases were about $28 million more expensive than purchasing the same capacity from PJM over the period the Sithe TPPA was in effect (November 7, 1999 through May 31, 2002). However, in its Order approving the fossil sale and the Sithe TPPA, the Board found these capacity charges to be reasonable, and authorized their recovery via the Company's charges for BGS:

> These prices [the Sithe TPPA capacity prices] are in a range consistent with the capacity prices used in the determination of the average shopping credit approved for the Company by the Board [in the Summary Order]. As a result, these capacity prices that are specified in the TPPA

[59] A copy of which was provided in response to RAR-BGS-17.

> are in the best interest of the Company's customers since they will help insulate the Company from price spikes that may occur from time-to-time as it serves basic generation customers, and which otherwise could ultimately be passed on to customers. Accordingly the Board **HEREBY FINDS** that the TPPA entered into by the Company with Sithe to be in the public interest, in accordance with applicable law, and the rates specified therein and the costs resulting therefrom to be reasonable and prudently incurred by the Company throughout the full term of the TPPA… and we **HEREBY PERMIT** the Company to flow through and/or full and timely recover the costs resulting therefrom as part of its Basic Generation Service.
>
> [Sithe Order at 15 (footnote omitted)]

Additionally, as the Company contended, by not including an energy provision in the Sithe TPPA, the Company attempted to get the highest price for its fossil assets, thereby minimizing stranded costs in accordance with Board policy. [60]

In quantifying its disallowance Staff found that the TPPA savings, as well as the savings achieved from restructuring the PPA with the Bayonne NUG project, were fairly and appropriately deductible from its imprudence quantification associated with the discretionary purchases. As summarized in Exhibit 2 attached to this Order, they totaled $176.5 million, and after deducting this amount from Staff's estimated $329.0 million of excessive costs incurred in making the non-TPPA discretionary purchases, Staff recommended a net disallowance of BGS deferred costs of $152.5 million.

In rebutting the Appendix B quantification (which as noted above was provided by the Company and is essentially identical to the quantification shown in Exhibit S-32), the Company's witness Mascari contended that not only did the use of the historical PJM prices not "reflect what would have occurred if different weather patterns and other market conditions had prevailed, something that can never be known in advance," but that the Company "almost certainly could not have purchased all of its BGS needs on the PJM spot markets at these historical prices, because purchase of all of its BGS requirements (as well as purchases by its Pennsylvania affiliates of all of their PLR requirements) on the spot markets would have substantially increased demand and otherwise distorted the prevailing spot market conditions so as to have resulted in higher spot prices." (JC-14 Supplemental Rebuttal, 25-3 to 25) Similarly the Auditors echoed the Company on these points: "The PJM prices [employed in the Appendix B analysis] are based on existing market conditions and do not reflect changes in price which would likely have occurred with increased volume of PJM purchases." (S-38 at Appendix B-1)

In each case, Staff asserted that the Company and the Auditors failed to recognize that in the absence of the Company's bilateral and third party purchases, the energy and capacity not sold to JCP&L and now available to be sold elsewhere would represent increased PJM supply that just as convincingly could be argued would, if not purchased by the Company in PJM's day ahead and real time markets, *decrease*, not increase,

[60] Mascari Rebuttal. (JC-14 Rebuttal, 6-1 to 11)

PJM spot prices. In actuality, however, Staff believed that the Company would have in fact purchased the same energy and capacity, only this time in the much more liquid and competitive PJM markets,[61] thereby avoiding, as a minimum, the demonstrably excessive risk premiums demanded for forward purchase commitments.

Nor did Staff find convincing the Company's argument that PJM's credit policy[62] would have limited the Company's ability to purchase replacement power from PJM, in view of the Company's creditworthiness (as evidenced by its A bond rating), past history of large interchange purchases, and importantly, the Board's Restructuring Order allowing the deferral of under-recovered BGS costs with interest and attendant assurance of recovery to the extent such costs were prudently incurred.

In contesting Staff's recommended BGS disallowance in its Reply Brief,[63] the Company again took issue with comparing its performance to the PJM benchmark, the starting point of Staff's disallowance, which the Company characterized as being hindsight-based, after-the-fact and in conflict with Staff's acceptance of the Auditors' definition of prudence. Moreover, a world in which the Company and its Pennsylvania affiliates purchased all of their requirements from PJM instead of pursuing the hedging strategy they actually followed was, to quote the Auditors, "a world that did not exist." (CRB at 79-80) Again quoting the Auditors, in the world that did exist, the Company maintained that large spot purchases by it and its affiliates would have had a substantial impact:

> JCP&L was not a major participant in the spot market other than to make up the difference between the fill and what it needed at the time, so that the spot market itself was relatively thin and shallow and had very – had low prices because only the marginal players were in it at that juncture…And to show a comparison with that market without JCP&L in it or GPU in it is not a real comparison for what the market might have looked like, had JCP&L not had a hedge strategy and been an active player in the spot market those prices would have been different…the market would have been different.
>
> [CRB at 80, citing 13T 79:13 to 80:4]

In contrast to this assertedly uncontroverted view, the Company characterized Staff's suggestion that PJM spot prices might actually have *decreased* in the absence of JCP&L's hedging as being speculative and unsupported by record evidence. Moreover,

---

[61] With respect to the liquidity of a market, Company witness Graves agreed that the number of buyers and sellers present in the market "matters a lot" (8T 73-16), and as compared to the approximate 235 PJM members, that there were "probably fifty" brokers from whom JCP&L could have purchased its BGS supply, and even fewer parties willing to enter into negotiated private contracts. (8T 72-21 to 73-11.)

[62] Which, as indicated in the discussion on pages 6 and 7 of JC-14 Supplemental Rebuttal, appears to have been triggered by the default of utility.com, a small retail provider.

[63] As noted above, Staff's recommended BGS disallowance was based on the data in Exhibit S-32, which while providing more detailed capacity costs, did not otherwise differ significantly from the data on which Appendix B of the Audit Report is based.

this possibility was assertedly contrary to the testimony of every witness who addressed this issue: the Company's witness Mascari, who testified that spot prices would have increased as a result of the increased JCP&L demand, and witnesses Graves and Chernick, who averred that the market at least would have been different than it actually was. (Id. at 81) Company witness Graves additionally alluded to the potential for market power manipulation in the spot market, which he maintained was more amenable than the forward markets to such manipulation due to so-called "scarcity bidding," or the "opportunity to withhold supply and raise the price with opportunistic bidders." (Id.)

In addition to increased demand, the Company asserted that if other factors, such as weather, gas prices and the like, none of which can be known in advance, had turned out differently, spot prices would have been different than those actually realized. Before the fact, there was even the possibility that prices "could skyrocket, as they did during the disastrous California experience in 2000-2001." That in turn, the Company maintained, "was precipitated in large part by the regulatory mandate that the California utilities purchase essentially all of their requirements on spot markets." (Id. at 82, including footnote 33) The Company also cited on-peak, real-time prices experienced in PJM in July 1999 of over 15 cents per kwh, and averred that the Company most certainly would have been excoriated if these, or spot prices comparable to those experienced in California had occurred, and it had not hedged its BGS obligation. (Id.)

The Company also cited an apparent inconsistency between the cost of JCP&L's discretionary purchases calculated by Staff in Atlantic Electric's deferred balance proceeding[64] and the cost on which Staff's recommended disallowance in this proceeding is based. In its Atlantic brief (at 40), in comparing the much higher cost of Atlantic's discretionary purchases to JCP&L's and RECO's, Staff indicated that the average cost of JCP&L's discretionary purchases was $49.68 per Mwh, as compared to $60 per Mwh in this proceeding (SIB at 160), with no explanation for the difference.[65] (Id. at 83, including footnote 35) Moreover, the Company maintained that by supporting the Advocate's adjustments in the Atlantic proceeding, the basis for which, at least in part, was Atlantic's failure to enter into long-term purchased power contracts or hedging agreements to protect against excessive price spikes, Staff took an "almost diametrically opposite position" to the "results-oriented" position taken here. (Id. at 82-83) The Company also maintained that Staff summarily dismissed, without supporting record evidence, the Company's assertion that PJM's evolving credit policies would likely have precluded the Company from purchasing the quantities of power required under Staff's default option of purchasing all of its requirements from PJM. (Id. at 83-84)

As for Staff's assertion that the Company's model appeared to allow "speculative" forward purchases, the Company, citing Webster's definition of speculation ("the assumption of unusual business risk…in hope of gain; *esp.*: to buy or sell in expectation

[64] I/M/O the Petition of Atlantic City Electric Company, d/b/a Conectiv Power Delivery for Approval of Amendments to its Tariff to Provide for an Increase in Rates for Electric Service, Docket No. ER02080510.

[65] This apparent inconsistency was also cited by the Company in its August 29, 2003 Motion for Reconsideration (at 16, footnote 10). As explained in greater detail below, the apparent inconsistency results from including JCP&L's TPPAs in Staff's Atlantic comparison and excluding them (treating them separately) in Staff's JCP&L analysis.

of profiting from market fluctuations."),[66] asserted that under the Final Restructuring Order it was not permitted to realize a profit on any aspect of its BGS activities, and thus there was no incentive for it to engage in such speculation. As for Staff's suggestion that the Company's models could establish targets in excess of load, while conceding that this could be true if the targets are compared to the average peak load (the average of all 16 peak hours on all non-holiday weekdays during a given month), the Company asserted that this was not the case if the targets are compared to the forecasted hourly peak demand for the delivery month. Moreover, that was the peak load to which its model (the X-method, in this instance) was keyed. However, "neither the Company's targets, nor its ultimate 'advance' commitments (in the form of forward contracts and pre-existing committed supply, such as NUGs and owned generation) exceeded the forecasted, normal-weather peak load." (Id. at 87-88)

The Company also contended that Staff's suggested use of historical cost as a benchmark for assessing the reasonableness of the cost of the Company's forward purchases was not relevant, because such a benchmark ignored the fundamental fact that during the Company's long history of purchasing energy from PJM, generating units were dispatched on the basis of variable operating costs in contrast to the post-restructuring market-based system now in place, under which generator owners can bid whatever they want to up to PJM's $1,000 per Mwh bid cap. (Id. at 93) Additionally, the "lock and load" strategy was not adopted in *de facto* recognition that basing purchasing decisions on historical cost was a "better way to go," as suggested by Staff, but rather to establish a "floor" that if approached, would trigger accelerated forward purchasing on the assumption that forward prices were not likely to go any lower.

With respect to the Company's failure to adequately document its purchasing decisions by not saving the price quotes it received other than the quotes it accepted, as alleged by the Advocate and Staff, the Company responded by stating that many of the quotes were voice quotes for which no formal record was kept, and in any event that retaining "mounds of irrelevant data about price quotes" was not needed in light of the Company's procedures, which assertedly insured that purchases were made at prevailing market prices. Moreover, the Auditors shared this view, asserting as they did "that in a prudence review one does not need a piece of paper for every finding and conclusion (13T 39:4-5), so long as one is comfortable with the organization, policies, procedures, methodologies, etc., being applied (13T 40:1-3)." (Id. at 95, as quoted by the Company)

The Company also re-iterated the propriety of the fundamental objective of its procurement policy ("to minimize the difference between BGS revenues and costs over a wide range of possible outcomes, i.e., to reduce the volatility risk"), and again cited the Auditors' findings in support of this objective (at VII-25 to VII-26 of the Audit Report).

While standing by its position that the higher cost of BGS procurement in New Jersey as compared to the PLR procurement costs of the Company's Pennsylvania affiliates is the appropriate benchmark for calculating the BGS disallowance, in its Reply Brief the

[66] In the context of Staff's discussion of the appropriateness of the objective of the Company's BGS procurement model, by "speculative purchases" Staff meant forward energy purchased in excess of the amount needed on the expectation of re-selling the excess at a profit (for more than its cost) in order to reduce the seasonal (summer) cost of power in excess of the annual average. (SIB at 147-148; 150) Contrary to the Company's assertion, Staff did not suggest that the Company's models *required* speculative purchases – only that they appeared to allow them. (Id. at 147)

Advocate asserted that Staff's analysis nonetheless reinforced the Advocate's position that the Company did not incur its BGS costs prudently. (RIB2 at 79) More generally, Staff's analysis was consistent with the Advocate's position that the Company should have been making after-the-fact performance comparisons all along, as asserted by the Advocate's witness Chernick:

> The Company should have been conducting after-the-fact comparisons through the BGS-procurement period because information on the performance of a strategy is vital to determination of whether the strategy should be continued. If every transaction of a particular type that JCP&L made turned out to be uneconomic, prudent management would require that the use of that type of transaction be re-examined, restricted, or stopped entirely. I do not believe that JCP&L could prudently acquire BGS supply without such information.
>
> [Id., quoting R-59 at 32-10 to 16]

Moreover, as asserted in its Initial Brief (at 35-39), the Advocate maintained that the Company's failure to develop an after-the-fact benchmark against which its performance could be measured ignored the advice of its own consultant, Mr. Graves of the Brattle Group. The Company in turn disputed this contention, asserting that Mr. Graves agreed that the establishment of such a benchmark would be acceptable only if it were agreed to in advance by the Company and the Board. (CRB at 97)

(c) Pennsylvania vs. New Jersey Supply Costs

As indicated above, the Ratepayer Advocate recommends that the Board disallow recovery of the $239 million difference between the actual cost of the Company's non-NUG and TPPA purchases and what the cost of these purchases would have been during the first three years of the transition period if they had been priced at the comparable prices paid by the Company's Pennsylvania affiliates, Met-Ed and Penelec. (RIB2 at 23; R-59 at 7-1 to 7-14)

Mr. Chernick, the Advocate's witness on this issue, asserted that this differential may have resulted from differing incentives in the two states, in that unlike JCP&L, Met-Ed and Penelec were fully at risk for their BGS costs (PLR costs as they were known in Pennsylvania) in excess of the level allowed in rates, at least until June 2001 when the Pennsylvania Public Utilities Commission ("PaPUC") authorized their deferral through the year 2010, after which any amounts still unrecovered would have to be written off. [67] JCP&L on the other hand knew from the start that its excess BGS costs were deferrable. Moreover, their recovery was not subject to a firm termination date. (R-59 at 7-25 to 8-12)

[67] By Order issued on June 20, 2001, the PaPUC approved a settlement that, *inter alia*, permitted Met-Ed and Penelec to defer the difference between their charges to retail customers for PLR service and their actual cost of supply beginning January 1, 2001 and continuing through year-end 2005. On appeal, on February 21, 2002 the Commonwealth Court of Pennsylvania overturned the PaPUC's Order with respect to this issue (the issue of deferred accounting for PLR costs and revenue). On March 25, 2002, FirstEnergy appealed the Commonwealth Court's decision to the Pennsylvania Supreme Court, which denied the appeal on January 17, 2003. (FirstEnergy Letters to the Investment Community dated March 25, 2002 and January 21, 2003.)

Mr. Chernick noted that in its response to discovery request RAR-BGS-6,[68] the Company argued that the average cost per kwh of its BGS purchases exceeded those of its Pennsylvania affiliates because 1) its peak requirements were higher; 2) its NUG costs were higher; 3) its level of customer shopping was significantly lower; 4) it was affected significantly more by congestion costs; and 5) because its load response to extremely hot weather tended to be higher due to the greater penetration of air conditioning in its service territory. (Id. at 9)

Mr. Chernick found these arguments unpersuasive. While agreeing that JCP&L's load factor is lower than those of the Pennsylvania companies, and that JCP&L may face higher congestion costs than they do, the Company did not quantify the effect of either of these differences. As to the other factors, he asserted that NUG costs were not relevant to the comparison, that higher shopping levels in Pennsylvania would tend to draw off higher load factor customers leaving a peakier and therefore more expensive to serve residual load, and that the cost differentials between the two states were not driven by summer air conditioning load because the differentials tended to be more pronounced in the fall and winter months. (Id. at 9 to 10)

In responding to witness Chernick's suggestion that there may have been a greater incentive to control costs in Pennsylvania than in New Jersey, Mr. Mascari emphasized that the same methods, policies and procedures were consistently applied in both jurisdictions, and averred that the regulatory risk attendant upon the Board's prudency review of the Company's deferred balance in New Jersey was just as great as the profit or loss risk present in providing PLR service in Pennsylvania. The New Jersey risk, in fact, was disclosed in the Company's 1999 10-K filed with the Securities and Exchange Commission ("SEC").

As to the reasons why its BGS procurement costs were higher in New Jersey, Mr. Mascari deferred to Company witness Graves, who contended that Mr. Chernick failed to recognize the distinguishing factors that would account for the higher price JCP&L paid for power as compared to the prices paid by its Pennsylvania affiliates. Mr. Graves contended that by simplistically comparing the average price JCP&L paid for its non-NUG, non-TPPA energy purchases[69] during the transition period ($45.88 per Mwh) to the comparable rates paid by Met-Ed and Penelec ($39.90 per Mwh and $40.26 per Mwh, respectively) in arriving at his recommended disallowance of $239 million, the Advocate's witness failed to analyze how much of the difference in the average rates resulted from the differing costs and proportions of the several types of energy and capacity products that made up the supply portfolios of the three companies, and also failed to take into account the differences in the companies' gross and residual load shapes (their loads less committed supplies), congestion charges, degree of customer shopping and the volatility of the regional nodal spot prices they faced. (JC-19 Rebuttal at 9 to 10) Differences in the LMPs between PJM's Western Hub, where the Pennsylvania companies purchased their energy, and the Jersey Zone, where JCP&L's purchases are made, could, for example, account for as much as 5% of the 13% difference in the average rates. The higher volatility of the Jersey Zone prices also made

[68] Incorrectly referenced as being the response to RAR-BGS-56. The correct reference (to RAR-BGS-6) is included in Schedule CAM-18 attached to Company witness Mascari's Rebuttal Testimony (JC-14 Rebuttal).

[69] Energy purchased under pre-existing PPAs with other utilities was, however, included in Mr. Chernick's analysis, according to Mr. Graves.

them more costly to hedge, and exposed the Company to a greater number and magnitude of price spikes in the summer when its weather sensitive load would also be peaking. (Id. at 9-1 to 11-17) In that power purchased to meet JCP&L's peak load is driven by summer air conditioning load in contrast to the loads of the winter peaking Pennsylvania companies, it cannot be expected to cost the same. After deducting each company's committed supply, JCP&L's residual load is even more costly to serve in view of its greater apparent volatility and lower load factor when measured this way (21% versus 44% for the Pennsylvania companies). (Id. at 7-17 to 14-15)

While the same methods and personnel were employed in securing the supply requirements of all three companies, the supply targets and outcomes could differ for each company due to differences in load shapes, weather sensitivity, spot price volatility and forward price differences. Moreover, if the hedge targets were different in the two states (which in general they were), and the realized spot prices differed as well, the resulting costs would necessarily differ despite having the same purpose and design. (Id. at 15-16 to 18-2)

The Auditors also found that the same methodology for determining fill targets and procurement requirements was employed in the two states, and cited many of the same factors noted by witnesses Mascari and Graves as the reasons for the differing prices between the two states. (S-38 at VII-48 to VII-49)

Other than Mr. Graves' comparison of the differing LMPs faced by JCP&L and its Pennsylvania affiliates, which he suggested could account for 5% to 7% of the 13% price differential, Staff noted that the effect of the other factors cited in the Company's testimony was not quantified. Staff did, however, concede that they could plausibly account for the remaining difference, and therefore asserted that its more general benchmark, the default option of purchasing from PJM, provided a better measure of assessing the effectiveness of the Company's BGS procurement.

2. MTC Deferred Balance

(a) Return on TBD Plant

In auditing the Company's BGS deferred balance incurred during the first three years of the transition period, the Auditors found that there was no Board Order authorizing the Company to use a 14.64% rate of return in calculating the return on its generation assets included as part of the costs recoverable by BGS revenue. (S-38 at I-4) When queried by the Auditors as to the authority it relied on for using this rate, the Company responded by citing another utility's Final Decision and Order permitting that utility to calculate the return on its generating assets at the rate of 13.0 %, pre-tax.[70]

In response to a discovery request, the Company further indicated that the 14.64% rate was the rate on which the 1996 cost of service study employed in its restructuring proceedings before the OAL and the Board was based. (S-49) Staff, however, noted that a "more current overall cost of capital of 9.50%" was reflected in the stipulated reduction in the Company's average distribution rate, from 3.70 cents to 3.45 cents.

[70] I/M/O Atlantic City Electric Company's Rate Unbundling, Stranded Costs and Restructuring Filings, Docket Nos. EO97070455, EO97070456 and EO97070457, Order dated March 30, 2001, paragraph 22 on page 92.

(Final Restructuring Order at 93) Accordingly, Staff recommended that the Board direct the Company to recalculate the return component of the revenue requirement of its generation assets (other than Oyster Creek) included in BGS recoverable costs during the transition period using the pre-tax equivalent of the 9.50% overall rate of return, consistent with the method employed by Atlantic City Electric Company,[71] including the monthly deduction of depreciation charges when computing the return. The Advocate recommended that the ALJ and the Board "disallow the Company's self-authorized collection of a 14.64% return on its generation assets through BGS revenues." (RRB at 81).

(b) Above-Market NUG Costs and Mitigation

To the extent the cost of the Company's NUG purchases, priced at market, are not recovered from its BGS revenue, the "above market" component is included in the MTC.

In his Direct Testimony the Ratepayer Advocate's witness Chernick asserted that the Company had failed to demonstrate any management of its NUG contracts to minimize NUG costs. (R-59 at 32-22 to 33-2) In rebuttal, Mr. Mascari cited the Company's continuing and previous efforts that began in the early 1990's, as evidenced by the pre-construction buyouts of the American Ref-fuel, Crown/Vista and Freehold PPAs, thereby achieving estimated ratepayer savings of $620 million on a net present value ("NPV") basis over the life of the terminated contracts. (JC-14 Rebuttal at 23-5 to 25-12) More recently, the Company negotiated pricing concessions from other project owners aggregating approximately $60 million on the same NPV basis, and received an upfront payment of $25.4 in return for negotiating revised pricing of the PPA with the Bayonne project. Id. Moreover, the Company files a quarterly report with the Board and the Advocate that provides the status of ongoing negotiations with each project owner as of the end of that quarter.[72] Id.

In its Initial Brief, the Advocate expanded upon its criticism of the Company's efforts to mitigate above-market NUG costs, maintaining that it had failed to achieve any meaningful mitigation since the issuance of the Board's Summary Restructuring Order in May 1999, as shown by the approximate $1.0 billion of such costs reflected in this proceeding. Although relatively small savings of $6.3 million were achieved from re-negotiating the operating agreements for the supply of natural gas to the Newark Box and Parlin projects, and although talks with the Bayonne project are continuing, there has been no mitigation of above-market costs associated with the other major projects, including an estimated $250 million associated with the South River Project over the three years 2000-2003, and $114 million associated with the Lakewood project over the same period. The Advocate also cited the Auditors' findings with respect to the Reliant proposal rejected by the Company, and its less than aggressive efforts to mitigate above market costs associated with the smaller projects (Camden, Gloucester and Kenilworth). Accordingly, the Advocate recommended that the Board not permit the Company to collect interest on the NUG portion of the deferred balance, which it quantified at approximately $59.5 million, thereby apportioning some responsibility for the Company's alleged failure to mitigate NUG costs to shareholders. (RIB at 27-31)

[71] Deducting the actual weighted cost of debt and preferred equity from the overall rate of return of 9.50%, and then grossing up the residual to determine the pre-tax common equity component.

[72] As directed by the Board in the Merger Order (its October 9, 2001 Order in Docket No. EM00110870 approving the GPU/FirstEnergy merger).

In responding, the Company in its Reply Brief urged the dismissal of the Advocate's proposed interest disallowance on procedural grounds, inasmuch as it appeared for the first time in the Advocate's Brief, and additionally maintained that it was in any event unsupportable on the merits, as evidenced by the $25 million payment received from the Bayonne project in December 2002, all of which was credited to the deferred balance, and the Company's (Mr. Mascari's) testimony on the Company's NUG mitigation efforts, with which, other than their finding on the small projects, the Auditors took no issue. (CRB at 101-103)

The Auditors provided a more comprehensive review of the history and results of the Company's NUG mitigation efforts in Chapter VIII of the Phase I Audit Report (S-38). While finding that the Company's mitigation efforts had complied with the Board's filing requirements, and that the Company for the most part had maintained a reasonable and prudent program for NUG mitigation since well before the Board's *Towner* Order, at least for its larger projects, the Auditors did conclude that the Company was less than aggressive in pursuing mitigation opportunities for the Camden, Gloucester and Kenilworth projects aggregating 50 Mw of contract capacity, and accounting for approximately $48 million of total above-market NUG costs of $770 million estimated for the period 2000-2003. (Id. at VIII-9, VIII-13; Exhibit VIII-2) Should the Board find that a disallowance related to these less than aggressive efforts was warranted, the Auditors suggested quantifying the disallowance at 10% of the contract payments made to the three NUGs during the transition period, or $5.6 million.[73] The 10% was assertedly the savings target internally set by the Company for its restructuring efforts. (Id. at VIII-16) As part of the Phase II Audit the Auditors also recommended re-examining the Company's rejection of a comprehensive NUG contract restructuring proposal made by Reliant Energy, and also investigating the reason for the delay in the receipt of the Bayonne PPA restructuring payment. (Id. at VIII-15)

In Supplemental Rebuttal Testimony filed on April 21, 2003, Mr. Mascari pointed out that the 10% savings target applied only to the above-market component of the NUG contract payments, not the entire amount, and if the 8% savings percentage actually achieved in restructuring the pricing terms of the Bayonne PPA were applied to the Camden, Gloucester and Kenilworth above market contracts payments, the disallowance suggested by the Auditors would be reduced to $2.4 million. (JC-14 Supplemental Rebuttal at 18-3 to 19-17)

Moreover, Mr. Mascari asserted that the Company had appropriately prioritized its NUG mitigation efforts in view of the uniqueness of the Camden and Gloucester projects, both of which are resource recovery facilities either owned, financed or subject to approvals by governmental entities (including the New Jersey Department of Environmental Protection) that complicate the negotiation process. (Id. at 20 to 21) The electric output of the Kenilworth project, a 15 Mw qualifying facility, has been limited to 5 Mw due to increased steam host demand, and would therefore yield minimal savings from a contract renegotiation. Id.

Staff found the Company's arguments for not accepting the suggested disallowance proposed by the Auditors convincing. With respect to the delay in the closing of the Bayonne PPA restructuring and the Company's rejection of the Reliant proposal,

[73] Corrected to $5.7 million at the hearing on April 28, 2003. (13T 29-2 to 7; Exhibit S-40)

however, Staff agreed that both should be investigated further in Phase II of the audit. Staff also noted that in addition to mitigating NUG costs through buyouts or buydowns of the related PPAs, the Final Restructuring Order directed the Company to maximize the value of NUG contract power either through market sales, or by devoting it to BGS supply:

> GPU [JCP&L] has an ongoing obligation to take all reasonable measures to mitigate the stranded costs associated with NUG utility Purchase Power Agreements, including optimizing the market revenues received for the sale of power and other marketable services derived from the Purchase Power Agreements on the open market, or for use of Non-Utility Generator and Utility Purchase Power Agreement power to offset purchases of energy and capacity or other services otherwise necessary to serve Basic Generation Service customers…
>
> [Final Restructuring Order at 109, paragraph 22]

In view of this requirement, and the possibility that using NUG energy to supply BGS could provide greater value than reselling the NUG energy to PJM,[74] and to monitor and assess the value received from the resale of the NUG energy on an ongoing basis, Staff recommended that in addition to the quarterly reporting requirement previously ordered by the Board, that the Company be directed to file monthly reports that show, for each NUG project, the energy and capacity purchased (Mwh and Mw), the amount paid for the energy and capacity, the disposition of the energy and capacity (i.e., whether it was resold in the wholesale market or otherwise), the amount received from the sale of the energy and capacity, as well as the value of the energy if it were priced at the average monthly PJM LMP and capacity deficiency rate, and the value if it were priced at the rate payable for BGS supply obtained pursuant to the statewide auction.

3. Auditors' Report

JCP&L

While asserting that the Phase I Audit Report supported the overall reasonableness and prudence of its BGS procurement, the Company contested the cost disallowances recommended in the report and several of its other recommendations. Citing Exhibits S-41 and S-42, the Company noted that the report was the work of 16 professionals, including six CPAs and specialists in management, finance, engineering and operations, as well as consultants experienced in power supply procurement and NUG contract renegotiations who collectively devoted over 2,500 hours to the audit at a cost of more than $450,000. The Company summarized the report's findings as follows:

- JCP&L's strategy for meeting its BGS procurement responsibilities was informed and reasonable.

[74] Staff also cited this possibility for the output of Yards Creek and the Forked River CTs.

- ? The organization established to perform JCP&L's BGS procurement function was structured in a logical manner.

- ? GPU appropriately supplemented its expertise through the use of external consultants.

- ? GPU senior management took an active role in overseeing the development of BGS procurement requirements.

- ? GPU developed a reasonable strategic framework for meeting BGS procurement needs.

- ? The use of a methodology that attempts to minimize BGS procurement costs over a range of possible outcomes was consistent with Board requirements and was reasonable.

- ? GPU's BGS supply procurement practices appropriately evolved over time.

- ? GPU, and subsequently FirstEnergy, appear to have managed the Pennsylvania provider-of-last-resort and New Jersey BGS procurement in a fair and equitable manner.

- ? GPU's Pennsylvania provider-of-last-resort procurement strategy and provider-of-last-resort procurement implementation activities were consistent with those employed by GPU in meeting JCP&L's BGS obligations. In both cases targets were set, first using the X-method, and then using the HOST method. Procurement activities were governed by the status of committed supplies against target levels and expectations of price movements using similar considerations in both jurisdictions. Differences in actual targets and procurement levels are attributed to differences in the underlying makeup of the customer base and their associated load profiles in Pennsylvania and New Jersey, rather than any attempt to manage costs in Pennsylvania or shift costs from Pennsylvania to New Jersey.

- ? It was reasonable to include a need to avoid buying quantities large enough to move the prices upward in either the forward or spot markets, as an objective of the procurement strategy.

- ? The Company reasonably deviated from its fill target plan when it was faced with unusual market uncertainties or opportunities, including for the summer of 2001 and 2002, with the exception of [alleged] excess procurement of supply for the summer of 2001.

- ? JCP&L monitored short- and long-term market conditions and prices on a daily basis.

  [CIB at 153-154, quoting Chapters I and VII of the Phase 1 Audit Report]

The Company did, however, take issue with the $11.7 million disallowance recommended by the Auditors in finding that the Company had imprudently exceeded its fill (hedge) targets established for the summer months of 2001. As asserted by the Company, the alleged excess procurement was due to the introduction of the HOST model in February 2001, which together with declining forward prices, substantially reduced the hedge targets (the portion of the targets to be met by forward purchases) for the months at issue. However, the higher targets previously established by the X-model had already been procured, and the Company maintained that if it had sold the excess, it would have been forced to rely more heavily on the PJM spot market, since the Company's ultimate supply obligations had not changed. Increased reliance on PJM in turn could have exerted upward pressure on prices, especially at a time when PJM was imposing new, more stringent credit policies. (Id. at 155)

The Company also took issue with the Auditors' questioning the lack of an energy TPPA with the purchaser of its fossil units, maintaining that encumbering the sale with an energy TPPA would not have maximized the sale price of the units, thereby increasing stranded costs, contrary to the Company's (and Board's) divestiture objectives. Moreover, experience with Homer City, a large coal plant partly owned and subsequently divested by Penelec, assertedly indicated that a capacity only TPPA option was more advantageous, based on the indicative bids received when both energy and capacity TPPA options were offered to the bidders for that plant. (Id. at 155-157)

The Company additionally took issue with the Auditors' suggested disallowance of $5.6 million[75] for the Company's alleged failure to devote sufficient effort toward mitigating the cost of the Camden, Gloucester and Kenilworth PPAs. In the Company's view, this would have been a misplaced use of its NUG mitigation resources, given the small size of these projects and complicating factors such as the need to obtain the approval of county financing authorities and the New Jersey Department of Environmental Protection for changes in the projects' PPAs. Moreover, the 10 percent savings target assumed by the Auditors applied only to the above-market cost component, not the entire contract payment, and if corrected, the disallowance would be reduced to $2.4 million. (Id. at 160-163) The Company also took issue with the Auditors' proposed Phase II review of the delay in the Bayonne closing and the Company's rejection of the Reliant proposal, as well as the Company's alleged failure to avail itself of weather hedges. (Id. at 163; 157-159)

In contesting other issues raised by the Auditors, the Company asserted that the determining factor in setting the period over which Oyster Creek costs were to be amortized was the date the unit's operating license would expire in the absence of a sale or shutdown (December 31, 2009), and thus that the 11 years noted in the Final Restructuring Order was simply a rounded amount. In defending its use of the 14.64% return in calculating the revenue requirement of the fossil units, the Company asserted that this was the pre-tax return that formed the basis for the unbundling of its rates, as approved in the Final Restructuring Order. (Id. at 167-169)

RPA

The Ratepayer Advocate was sharply critical of the Phase I Audit Report, asserting that it:

[75] Corrected to $5.7 million in S-40.

> lacks demonstrative evidence that it is the product of thorough and independent analysis. The Audit Report is riddled with instances in which key conclusions, definitions, and explanations are verbatim copies of material provided by the Company in either testimony or discovery responses. The appearance is one of wholesale adoption by the Auditors of the Company's representations without any independent analysis of those positions by the Auditors. As such, the Audit Report is only as strong as the Company's representations, and is weakened further in that it cannot demonstrate adequately that [the Auditors] in fact investigated or otherwise plumbed beyond the surface of the Company's actions.
>
> [RIB at 39]

The Advocate went on to cite several parts of the report, including language appearing in the "Findings and Conclusions" section, that were quoted verbatim, or nearly so, from testimony or discovery responses submitted by the Company without having been attributed to the Company.[76]

The RPA also faulted the report for not utilizing external benchmarks against which the Company's performance could be compared (RIB at 40), and questioned how the Auditors could have independently verified the information on which they relied, given the Company's alleged lack of record keeping and other documentation for what it did. (RIB at 44-46)

Staff's Position

At Staff's request the Audit Report included a comparison of the cost of the Company's "discretionary" energy and capacity purchases[77] made during the first three years of the transition period to the cost of purchasing the same energy and capacity from PJM. (S-38, Appendix B) The comparison was based on data supplied by the Company, and showed that the actual cost of the Company's discretionary purchases during this period was $1,119 million, as compared to $793 million if the energy and capacity purchases were priced at PJM prices. The apparently rounded difference of $327 million represented an increase of over 40%. The Auditors noted that this analysis was retrospective in nature, and was not considered in their determination of prudence.

[76] See RIB at 40-44. When this issue was raised at the April 28, 2003 hearing, the Auditors (Laros) testified that the "material in here [the unattributed quotes] is felt by me to be a valid description of the factual information we were provided to present as verified through interview notes or interviews or other discovery…And I didn't feel it was necessary to recraft what I thought were apt descriptions of various matters." (13T 33 8 to 15 as quoted in RIB at 40) In its Reply Brief the Company also defended the Auditors' use of the unattributed quotes, asserting that once the information on which the Auditors' conclusions were based had been independently verified, "there was no reason to re-invent the wheel (or re-write the treatise) if the point had already been cogently articulated by the Company. Use of common language to express independently-derived conclusions does not in any way suggest a lack of independence." (CRB at 100; also see pages 98-99, 101)

[77] Energy and capacity purchases other than those made pursuant to TPPAs and pre-transition PPAs with other utilities and NUGs, i.e., non-TPPA discretionary purchases are the combination of two-party, bilateral and PJM purchases made by the Company in carrying out its BGS procurement strategy.

Moreover, they averred that the PJM prices were based "on existing market conditions and do not reflect changes in price which would likely have occurred with increased volume of PJM purchases." (Id. at B-1)

As discussed more fully below, Staff effectively subsumed the Auditors' recommended BGS disallowance of $11.7 million within its proposed BGS disallowance, which was based on the PJM benchmark and a review of the Company's procurement during the period from December 1999 through July 2000 in addition to the summer months of 2001 and 2002 analyzed by the Auditors. Staff agreed that the Company's use of the 14.64% pre-tax return in calculating the revenue requirement of the fossil units had not been authorized by a Board Order, and that the delayed Bayonne closing and the Reliant NUG proposal rejected by the Company should be reviewed further in Phase II of the audit. Staff did not agree, however, with the Auditors' suggested disallowance of $5.7 million of above market NUG costs.

4. SBC Deferred Balance/Charges

(a) Nuclear Decommissioning Funding

As permitted by the EDECA, nuclear decommissioning costs ("NDC") are one of the categories of costs recoverable by the SBC. N.J.S.A. 48:3-60.a.(2). As shown in Exhibit S-4, the Company proposed reducing the annual level of TMI-1 decommissioning-related charges included in the SBC, increasing the level of annual TMI-2 and Saxton decommissioning funding, and keeping the level of Oyster Creek decommissioning-related charges unchanged.[78] While in the aggregate the level of NDC funding was little changed, due to an increase in the level of sales the amount to be included in rates on a per kwh basis is reduced compared to the current charge per kwh, yielding an annual reduction in the NDC component of SBC revenue of $5.6 million, as shown in Schedules MJF-5 and MJF-8 attached to Exhibit JC-3, the Direct Testimony of Company witness Michael J. Filippone.

As shown in Attachment B included in Exhibit S-5, the annual repayment of the Oyster Creek "top-off" payment of $18.220 million per year through the year 2009 is based on carrying costs accrued at the rate of 14.3% pre-tax. Staff recommended that this rate be reduced to reflect the rate of return allowed in the base rate case when the rates approved in this case become effective. While Staff did not oppose the proposed extension in the period over which the TMI-1 top-off payment is amortized, it appeared to Staff that the Company's calculation of the annual amount (an annuity, with interest at 5.5%) did not conform to the Board's TMI-1 Order. Thus Staff recommended that the Board should only allow, as the annual amount, the current unamortized balance amortized through 2009 without interest.

With respect to TMI-2, Staff did not find that the proposed annual increase was sufficiently supported in the record, and therefore recommended that there be no change from the current funding level of $2.291 million per year. With respect to Saxton, Staff recommended that the requested funding be disallowed in its entirety on the basis that

[78] Of these, only the TMI-2 and Saxton amounts provide for decommissioning costs as such. The TMI-1 and Oyster Creek amounts represent the repayment of "top-off" payments made to the decommissioning trusts transferred to AmerGen in accordance with the terms of the agreements of sale of the units to AmerGen (see Exhibit S-5 and the TMI-1 Order included in the response to S-JDEC-1).

the Saxton decommissioning is no longer being funded by Met-Ed and Penelec, the Company's Pennsylvania affiliates, and thus it would be unfair to New Jersey ratepayers to ask them to continue to fund this cost. (S-8.)

(b) Universal Service Fund (USF)

Since the implementation of the appropriate USF charge was not to occur before August 1, 2003, JCP&L proposed to defer recovery of its costs, including interest, to implement the permanent USF program until after the Company receives the Board Order in the pending USF proceeding. Neither the RPA nor Staff addressed this issue.

(c) Demand Side Management (DSM)

JCP&L recovers its regulated DSM costs through the SBC. The Company requests an annual recovery of $38.8 million, resulting in a decrease in its DSM of over $15 million. The RPA did not oppose the Company's request, but did address the Company's request for lost revenues as part of the Company's energy efficiency programs. Staff did not oppose the Company's request.

(d) Consumer Education (CED)

The Company proposes to recover all Board approved costs associated with the CED, along with any carrying charges, beginning August 1, 2003. The Company estimates that the CED costs will total approximately $5.6 million and proposes to recover these costs through a base charge of 0.0278 cents per kwh.

The RPA would disallow any recovery by the Company of its CED costs for Year 2 and Year 3. The RPA believes that the statewide CED failed to achieve its goals of increasing awareness among gas and electric consumers in the critical areas of energy competition, alternate energy suppliers, energy conservation and efficiency, and the availability of financial assistance to eligible consumers.

Staff believes the Company is entitled to recover its costs associated with the CED and agrees with the Company's proposed CED Tariff Rider of 0.0278 cents per kwh.

(e) Uncollectibles (UNC)

In accordance with the Stipulation of Settlement approved by the Board in its Order in the Customer Services proceeding, Docket No. EX99090676 ("CAS Stipulation"), recovery of the Company's uncollectible costs was moved out of its delivery charge and into an adjustable rider within the SBC on August 1, 2001. As agreed to in the CAS Stipulation, the adjusted five year average of FERC Account 904 totaling $4.92 million was moved into the SBC. The Company intends to continue the UNC charge at its current level, periodically truing-up its actual uncollectible expenses to UNC revenues to determine whether the Company's UNC is over-collected or under-collected. Neither Staff nor the RPA opposed the Company's proposal.

5. Other Issues

(a) Interim Recovery of BGS/MTC Deferred Balances

At its public meeting held on March 20, 2003, and as memorialized in a Secretary's Letter to the ALJs hearing the deferred balances cases of the four utilities dated March 25, 2003, the Board decided to recall a number of issues related to the securitization and/or amortization of each utility's deferred balances. Specifically, the Board's letter indicated that it was recalling the following:

> the issue of how much of the prudently incurred deferred balances should be securitized and how much should be amortized, and for those balances to be amortized, what is the appropriate length of the amortization and the interest rate. In addition, the Board is recalling the issue of whether all or part of the prudently incurred deferred balances are legally eligible for securitization under EDECA. The individual Administrative Law Judges should be making findings as to what the level of prudently incurred deferred balances is for each utility.
>
> The Board will be making findings as to the appropriate transitional amortization and interest rate for such deferred balances between August 1, 2003, until such time as a final Board decision is made on the issue of securitization v. amortization and any authorized transition bonds are issued. To the extent that the parties have offered opinions on the setting of transitional amortization and interest rates in their cases, those portions of their briefs will be reserved to the Board and decided by the Board as part of their final rate Order. The issues that are being recalled will be considered by the Board in the individual securitization petitions filed by the individual utilities. To date, only two utilities, Rockland Electric Company and JCP&L, have made such filings with the Board. Individual procedural schedules will be set for each of the securitization proceedings.
>
> [Letter to the Hon. Richard McGill, Irene Jones, William Gural and Diana C. Sukovich, Administrative Law Judges, from Kristi Izzo, Secretary of the Board, dated March 25, 2003]

Accordingly, and consistent with its recommendation made in Public Service Electric & Gas Company's, Atlantic Electric's and Rockland Electric Company's deferred balance proceedings, Staff recommended interim deferral recovery, i.e., the recovery of JCP&L's deferred BGS and MTC balances during the period from August 1, 2003 until the date of securitization closing, or such other date on which amortization in lieu of, or in combination with securitization of these balances begins, as determined by the Board, based on an amortization period of 10 years. With respect to carrying costs, Staff recommended that in view of the short period in which the transitional recovery is expected to be in effect, the rate on 7-year treasuries plus 60 basis points previously authorized by the Board be reduced to the rate on 1-year treasuries plus 30 basis points, or to about 1.6%,[79] based on the yields reported in the Federal Reserve Statistical Release dated March 3, 2003. Moreover, the amortization should be determined net of tax.[80]

Applying this recommendation to the Company's combined BGS and MTC balance after reflecting Staff's proposed BGS disallowance of $152.5 million ($535.3 million),[81] yielded levelized annual deferral recovery of $56.4 million.[82] On a per kwh of sales basis this equated to 0.2814 cents per kwh, based on normalized 2002 sales of 20,042 Gwh.[83]

(b) RAC and Other Interest Calculations

The Company argued in its Initial Brief that the interest rate of 6.25% previously authorized by the Board for accruing interest on the unamortized balance of RAC costs should be retained, i.e., not changed to the yield on constant maturity 7-year Treasury notes plus 60 basis points, as recommended by the Advocate's witness Richard LeLash. If, however, a change were to be made, the rate should be increased to the Company's overall cost of capital, as argued by Company witness Filippone in his Direct Testimony. (CIB at 187 citing JC-3 at 18-20) Mr. LeLash had also proposed that interest be compounded annually, and the Company did not object to this proposal, provided the compounding was applied only prospectively, and uniformly to all of the Company's deferred balances, not just the RAC. (CIB at 188)

Staff agreed that the use of the 7-year Treasury rate was appropriate as long as the recovery of RAC costs continued to be based on a 7-year rolling average, and that the rate should be changed annually at the time the RAC factor is changed. Consistent with its recommendation in the deferred balance proceedings of the other utilities, Staff also supported annual compounding, as well as calculating interest monthly on the monthly beginning and ending balance of all deferrals, including the Company's deferred balances incurred during the transition period.[84] (SRB at 7)

Going forward, i.e., effective August 1, 2003, for all non-RAC deferrals, Staff recommended accruing interest at the Company's actual average cost of short-term debt (debt due in one year or less), or if no short-term debt were outstanding, the rate available on comparable temporary cash investments. Moreover, both the interest rate and the balance to which it was to be applied would be determined "net of tax" (reduced by deferred income taxes associated with the deferred costs and deferred interest

---

[79] Later updated to 1.3%

[80] As illustrated in Exhibit 2 attached.

[81] $687.8 million from Schedule SDM-1A of Exhibit JC-13 ("12+0" Update) less Staff's recommended disallowance of $152.5 million.

[82] Determined by dividing $535.3 million by the annuity factor 9.49859, where n = 10 years and i = 0.9464 (1.6%, net of tax).

[83] From Schedule SDM-5 of Exhibit JC-13 ("12+0" Update).

[84] The Company calculated interest on its deferred balances annually during the transition period.

expense).[85] While the rate and method of calculating interest on RAC deferrals were ultimately stipulated to by the parties,[86] other than Staff, the parties did not address the post-transitional interest rate and methodology to be applied to the Company's other deferred balances.

VI. DISCUSSION AND FINDINGS – DEFERRED BALANCES

A. PRUDENCY OF BGS PROCUREMENT

Discussion:

Through the testimony of its witnesses Mascari, Stathis and Graves, the Company asserts that it has demonstrated that its BGS procurement strategy and the implementation of that strategy during the three years ended July 31, 2002 was reasonable and prudent. Moreover, with the exception of what the Company characterizes as only minor concerns, including a recommended disallowance of deferred BGS costs of $11.7 million, the Auditors have also found the Company's procurement strategy and its implementation to have been reasonable and prudent during that period. The Advocate and Staff disagree, and have proposed substantial BGS disallowances of $239 million and $152.5 million, respectively.

The Advocate's recommended disallowance is based on a comparison of the cost of the Company's BGS energy purchases to the equivalent costs incurred by its Pennsylvania affiliates, Met-Ed and Penelec, during the same three-year period. Like the Company, these utilities had divested their generating assets, and thus were faced with the same responsibility of obtaining PLR supply for those of their customers not electing to take generation service from third party suppliers. The Advocate's disallowance was quantified by comparing the average prices the three companies paid for energy purchases other than contractual purchases from NUGs and divested generating units during the period. On that basis the cost of JCP&L's purchases averaged $45.88 per Mwh, or about 14% to 15% more than the $39.90 and $40.26 paid by Met-Ed and Penelec, respectively. In each case, the amount paid does not include capacity costs, i.e., is for energy only.

The Advocate attributes the higher cost of the New Jersey purchases to the differing regulatory treatments of unrecovered BGS/PLR costs in the two states. Unlike New Jersey, where as part of the restructuring plans approved by the Board the state's

[85] While the Company deducted deferred income taxes associated with the deferred costs from the deferred balances in calculating interest during the transition period, it did not deduct deferred taxes associated with the deferred interest.

[86] As noted above, the RAC Settlement provides for interest on the over or under-recovered deferred RAC balance to be calculated on a monthly basis upon the average of the beginning and ending monthly balances of deferred RAC costs, less accumulated deferred income taxes associated therewith, at a rate equal to the rate of seven-year constant maturity Treasuries as shown in the Federal Reserve Statistical Release on or closest to August 1 of each year, plus 60 basis points. Interest shall be compounded annually on August 1 of each year, commencing August 1, 2004, by adding the accrued interest from the prior twelve-month period to the principal balance on which interest is calculated. The interest shall be calculated on a prospective basis only, beginning 45 days after the issuance of a Final Order approving the RAC Settlement.

electric utilities were permitted to defer such costs for future recovery, deferrals were not permitted in Pennsylvania. Thus, as indicated above, unrecovered PLR costs in Pennsylvania had to be borne by stockholders. Accordingly, the Advocate asserts, there was a strong incentive to control costs in Pennsylvania that was lacking in New Jersey. The Advocate additionally maintains that the computer models employed in setting the targeted levels of the Company's on-peak forward energy purchases were flawed, in that they had as their objective minimizing the effect of BGS/PLR procurement on pre-tax earnings (the difference between BGS/PLR revenues and costs), in contrast to what the Advocate maintains is the more appropriate objective of minimizing costs alone. When revenue exceeds costs (as it typically does in low load months), and although the Advocate does not suggest that the Company actively sought to achieve this perverse result, the earnings-based objective of the Company's models could, in theory, *increase,* not reduce costs. In addition to this assertedly flawed objective, the Advocate maintains that the models were inconsistently applied, and that their results were ignored outright in some instances.

The Advocate also faults the Company for inadequately documenting its actions and failing to perform periodic retrospective reviews of its BGS performance, thus depriving itself of potentially valuable feedback that could have resulted in improvements in its procurement activities during the transition period. In particular, the Advocate cites the Company's failure to develop internal and external benchmarks against which its performance could be compared and measured.

With respect to the Audit Report, the Advocate asserts that the Auditors' findings and conclusions relied too heavily on the Company's representations, even to the point of quoting the Company's testimony and discovery responses verbatim without proper attribution. Moreover, the Company's alleged lack of adequate documentation assertedly prevented the Auditors' from performing a truly independent audit.

Staff agrees with the Advocate on several points, including the asserted inappropriateness of the objective of the Company's models employed in setting monthly targets for forward purchases of on-peak energy. While minimizing the impact of PLR procurement on earnings may have been defensible in Pennsylvania, given the regulatory treatment of unrecovered PLR costs there, in Staff's view it clearly was not in New Jersey, where, in addition to permitting deferrals, the Board authorized the accrual of carrying costs on the deferrals at a relatively generous interest rate. If the interest actually paid was less than the Board's allowance, the deferrals could, in fact, have had a positive impact on earnings. Staff was also less certain that the models' assertedly inappropriate objective did not actually increase costs, a concern applicable to the HOST model in particular, given its complexity that in Staff's view effectively precluded all but a cursory review in this proceeding. On the other hand Staff avers that there is less ambiguity in identifying another of the models' asserted flaws, namely that they appeared to expressly allow forward purchases in excess of the Company's projected on peak energy requirements, thereby potentially exposing it to the risk of having to resell the unneeded energy at a loss.

Moreover, Staff maintains that this is exactly what happened in the months of June and July 2000. After analyzing a retrospective review of the Company's BGS procurement presented by the Brattle Group, the Company's consultant, in September 2000, Staff found that the Company purchased about 50% more on peak energy than it needed in these months at an average cost of $63.54 and $114.02 per Mwh, respectively, thereby incurring a loss in these two months alone of $53 million when the excess energy was resold in the PJM spot market for approximately $33 per Mwh. For the entire eight month period reviewed (the months of December 1999 through July 2000), the cost of the Company's on peak energy purchases exceeded what the cost of the equivalent energy would have been if purchased in the PJM spot market by approximately $82 million ($148.4 million versus $66.4 million). A difference that large, Staff avers, should have triggered a rethinking of the Company's basic procurement approach in contrast to implementing the relatively modest enhancement of dollar cost averaging recommended by the Brattle Group, which was estimated to save about $12 million over the period analyzed, as compared to the Company's hedging strategy then in place.

Staff accordingly found this lack of attention to the results of the strategy itself - an achieved cost of BGS purchases more than *twice* the cost of the equivalent energy if it had been purchased from PJM - to have been patently imprudent. In the plain words of Staff, "a reasonable person would have concluded that under its procurement methods, the Company was both purchasing more forward energy than it needed and paying far too much for it." Other than a passing reference to a cool summer in a footnote, no analysis of the reasons for the difference appears to have been performed by the Company or its consultants. Just as importantly in Staff's view, apart from the relatively modest change in the Company's procurement method recommended by the Brattle Group, potentially less costly alternative procurement strategies were not considered at that time, in September 2000, about half way through the first three years of the transition period when, again in the words of Staff, "a change in the Company's procurement method could have made a meaningful difference in the costs incurred during the balance of the period."

As to what alternatives the Company could have considered, Staff suggested increased reliance on the PJM spot market if pre-established limits on the prices the Company was willing to pay for forward energy purchases were exceeded. If forward prices were so high as to suggest that it was unlikely that the Company could do any worse by relying on the spot market (prices as high as the $114.02 per Mwh cited above, for example), then Staff avers that the Company should not have paid those prices. As an example of one alternative approach to the problem of deciding how much forward energy to buy, Staff cited a simple strategy of obtaining half of the Company's energy requirements from the spot market, and half forward, provided the forward prices were reasonable based on the Company's prior experience gleaned from having been a large purchaser of interchange energy from PJM. The Company's later adoption of the lock and load strategy following the FirstEnergy merger Staff views as having been a step in that direction. Moreover, Staff asserts that increased reliance on PJM was unlikely to have increased PJM prices, in that the increased supply made available in the absence of the Company's forward purchases would be expected to exert downward pressure on PJM prices. Additionally, in Staff's view the Company would in all probability have obtained its energy requirements from the same generating facilities as before, only this time through the much more liquid PJM market, thereby avoiding, as a minimum, the large risk premiums it paid for forward purchases.

While the Advocate quantified its recommended BGS disallowance by benchmarking the Company's performance against the average price paid by its affiliates for energy purchases in Pennsylvania, Staff's analysis employed the more general benchmark of the cost of equivalent purchases from PJM. As a second difference, Staff's comparison also included capacity costs, as compared to the Advocate's energy only analysis. In both cases, however, only the cost of so called "discretionary" purchases, i.e., purchases exclusive of contractual purchases made under PPAs with NUGs, and TPPAs with the owners of the divested generation units,[87] were considered.

Staff's comparison showed that the Company's BGS procurement costs would have been approximately $330 million lower during the first three years of the transition period if the Company's discretionary purchases had been made at the average price of equivalent capacity and energy purchased from PJM (approximately $42 per Mwh), as compared to the average price actually paid (about $60 per Mwh). Staff then reduced the $330 million difference by offsetting it with the relatively favorable results achieved from the Company's TMI-1 and Oyster Creek TPPAs, as well as the payment it received from re-negotiating the PPA with the Bayonne NUG project, yielding a net recommended BGS disallowance of $152.5 million. In estimating the savings from the TPPAs, the same method used in quantifying the disbenefit attributed to the discretionary purchases was applied; that is, the lower amount paid under the TPPAs was compared to the higher cost of purchasing the equivalent energy and capacity from PJM, and the difference subtracted from the discretionary purchase disbenefit.

In responding to the Advocate's recommended BGS disallowance, the Company argues that the average price it paid for its discretionary BGS energy purchases exceeded the comparable prices paid by its Pennsylvania affiliates because its peak requirements were higher, the level of its customer shopping significantly lower, and its summer air conditioning load proportionately greater than theirs. Additionally, the Company was assertedly subject to higher congestion costs due to transmission bottlenecks that typically impede PJM's west to east power flows. In rebuttal, and while conceding that the Company's load factor is lower than that of the Pennsylvania companies and that it may face higher congestion costs than they do, the Advocate avers that the Company did not quantify the effect of either factor. Moreover, the Advocate does not agree that the higher level of customer shopping in Pennsylvania made the PLR load of the Pennsylvania companies any less costly to supply, nor does it agree that the cost differences between the two states, which tended to be more pronounced in the non-summer months, could be explained by the Company's higher air conditioning load. While the Company did provide an estimated range of the impact of congestion costs, Staff agrees with the Advocate that the other factors cited by the Company had not been adequately quantified. Nonetheless Staff finds that they could plausibly account for the Pennsylvania/New Jersey cost difference, and thus recommends that its more general PJM benchmark be used as the yardstick against which the Company's performance should be measured.

The Company vehemently opposes the use of the PJM benchmark, indeed any external benchmark at all in judging the reasonableness and prudence of its BGS performance, maintaining instead that only the adequacy of its procurement plan itself and the extent to which it was followed should be so judged, a position concurred in by the Auditors. To compare its performance to PJM prices after the fact, with the benefit of hindsight, is, in the Company's view, nothing more than Monday morning quarterbacking.

---

[87] In Atlantic Electric's deferred balance proceeding, discretionary purchases were defined more broadly, i.e., they included purchases made under TPPAs, which Atlantic failed to obtain from the purchasers of its divested generating units, a significant issue in Atlantic's deferred balance proceeding that was not present to the same extent here. With the possible exception of not having secured an energy as well as a capacity TTPA with the purchaser of the Company's fossil units, Staff found that JCP&L's TPPAs turned out well, as discussed above.

As to the high forward prices it paid for energy secured for the months of June and July 2000, the Company defends them on the basis that even higher prices had been experienced in PJM in July 1999. Moreover, there was also the before-the-fact possibility that prices could skyrocket as they did in the chaotic California spot market in 2000 and 2001. Additionally, if the Company (and its Pennsylvania affiliates) had purchased all of their requirements from PJM, PJM prices assertedly would have been higher than they actually were due to the increased demand, and in any event the prices actually experienced reflected only one of any number of market outcomes, depending on such factors as weather and gas prices that cannot be known in advance.

With respect to Staff's contention that the Company's models appear to have allowed the establishment of monthly on-peak targets in excess of its peak load projected for the delivery month, the Company concedes that this could have been the case if the targets are compared to the average monthly peak load (the average of the 16 on peak hours on all non-holiday weekdays during the month), but not when compared to the hourly peak demand for the month, the peak load to which its models were keyed. Nor did the adoption of the lock and load strategy represent a shift to a more nearly cost-based procurement strategy, as suggested by Staff, but rather the setting of price points approaching marginal costs that when reached, were intended to trigger accelerated forward purchasing. As to not saving the price quotes it received when entering into forward purchases other than those of the winning bidder, the Company maintains that this was unnecessary in light of its procedures that insured that the purchases were made at prevailing market prices, a view concurred in by the Auditors.

Findings:

Pennsylvania vs. New Jersey BGS/PLR Procurement Costs

While the Advocate attributes the relatively better procurement results achieved by the Company's Pennsylvania affiliates to the regulatory treatment accorded unrecovered PLR costs in Pennsylvania, we, like Staff, find the factors cited by the Company in explanation of the differing cost profiles of the companies to be plausible, if not totally convincing in view of the Company's less than adequate quantification of the differences. That the same procurement team and methods appear to have been uniformly employed and applied in both states, at least until the Board-ordered separation of the Company's procurement function from the parent company's after the FirstEnergy merger, lends support to this view. We also note that the Advocate's and Staff's recommended disallowances are not mutually exclusive. Staff's more general PJM benchmark inherently subsumes whatever differences may have resulted from preferential treatment of the Pennsylvania companies, if indeed there were any, and accordingly we find Staff's recommended PJM benchmark to be the more appropriate of the two yardsticks to use for the purpose of quantifying imprudence on the Company's part.

Inappropriateness of the Company's Modeling Objectives

Both the Advocate and Staff find the objective of the Company's models, minimizing the effect of BGS/PLR procurement on pre-tax earnings, to have been inappropriate, and we concur. While recognizing that there is clearly merit to the Company's argument that a number of weather, price and demand scenarios should have been evaluated, in our view they could have been considered just as well by models having the more appropriate objective of minimizing costs (maximizing the difference between revenues and costs when revenues exceed costs, for example). From a New Jersey perspective, that would have been equivalent to minimizing the Company's deferred balance, an especially appropriate objective in view of the fact that while the Company admittedly faced disallowance risk in New Jersey, there was either no, or a potentially favorable earnings impact from the deferrals as such, for the reasons noted by Staff. Moreover, we fail to see why the same cost minimizing objective would not have been the better choice to employ in Pennsylvania as well. While not necessarily minimizing earnings volatility, it appears to us that a cost minimizing objective would have minimized the absolute effect of unrecovered costs on the earnings of the Pennsylvania companies as compared to the objective actually employed, minimizing the difference between revenues and costs.

We also do not view the model's apparent undue emphasis on reducing volatility to have been appropriate, clearly not from a ratepayer perspective, inasmuch as the Company's shopping credits remained fixed during each year of the transition period. Moreover, as Staff points out, pronounced seasonality in the cost of electric supply is normal and unavoidable, and the Company was fully compensated for the interest it may have incurred in financing seasonal increases in its BGS deferred balance during the transition period via the Board's relatively generous allowance of carrying costs at the rate on 7-year constant maturity treasury notes plus 60 basis points. Thus in addition to reducing the impact of BGS/PLR procurement on pre-tax earnings, we find that reducing the volatility of earnings was another of the models' objectives that was not necessarily relevant nor appropriate in New Jersey.

As distinguished from volatility as such, the Company asserts that a key objective of its procurement strategy was to minimize its (and from a cost standpoint, its ratepayers') exposure to price spikes and potentially extremely high spot prices, citing those experienced in PJM in July 1999 and in the chaotic California energy market in 2000-2001. As the Company points out, reducing risk via financial instruments and forward contracts was expressly contemplated in the Final Restructuring Order, and the Board recognized that the cost of these instruments and forward purchases could exceed the cost of spot market purchases. In the Company's case, however, the question is, by how much? In Staff's view, by too much, as evidenced by its analysis of the Company's forward purchases of on peak energy for the delivery months of June and July 2000. When confronted by forward prices in excess of 11 cents per kwh, Staff maintains that the Company should have concluded that it was not likely to do any worse by relying on the spot market, and should have done so rather than entering into forward contracts at those prices, and we agree. Moreover, beyond these two months we find the amounts paid for the Company's discretionary BGS purchases throughout the transition period to have been excessive, as discussed below, even after making a generous allowance for the risk premium demanded on forward purchases.

As to the California experience, we view that to have resulted from a number of factors unique to that state,[88] as evidenced by the fact that it has not been repeated in other

[88] A poorly designed spot market was only one of several factors that led to the California energy crisis that began in the early summer of the year 2000. See, for example, *The History of Electricity Restructuring in California*, Blumstein, Friedman and Green, August 2002, where the authors note that such factors included "a supply/demand imbalance combined with a retail price freeze that prevented supply and demand from equilibrating, exogenous increases in the prices of some key inputs [i.e. natural gas, as discussed elsewhere in the report], poor design of the

jurisdictions. Nor have the high on-peak PJM prices experienced in July 1999 been repeated on a sustained basis, suggesting that they, too, may have resulted from market immaturity or imperfections that have long since been worked out. In any event, we do not believe that a one-time occurrence of on peak PJM spot prices averaging 15 cents per kwh can be defensibly cited to justify paying prices well above the much lower PJM prices subsequently experienced in the months immediately following July 1999, i.e., in August 1999, typically a month in which prices are just as high, if not higher than they are in July. In that month, as reported by the Company in monthly reports filed with the Board, PJM's average on-peak billing rate to GPU, as it was then called, was 5.37 cents per kwh. Moreover, the average on peak billing rate declined steadily thereafter, to 3.08, 2.71, 2.26 and 2.13 cents per kwh in the months of September 1999 through December 1999, respectively.

Forward Purchase Targets in Excess of On-Peak Load

Staff asserts that the Company's models appear to have allowed forward purchases in excess of the Company's projected on peak energy requirements, thereby potentially exposing it to the risk of having to resell the unneeded energy at a loss. That, Staff avers, did in fact happen in setting the targets for the months of June and July 2000,[89] as discussed above, and the excess purchases in combination with the excessive prices paid for them assertedly increased the Company's BGS costs by $53 million alone in those two months. The Auditors' recommended disallowance of $11.7 million was also attributable in part to excess forward purchases targeted for the following summer (the months of June, July and August 2001), but in quantifying their disallowance, the Auditors compared the cost of the forward purchases actually made to the cost of forward purchases that would have been made if the Company had not deviated from its fill targets (including an excess of 274 Mw targeted for June 2001), as compared to reselling or purchasing the energy from PJM.

While conceding that the hedge targets established by its models could exceed the Company's monthly average peak load, the Company states that the targets did not exceed the single peak hourly load projected for the delivery month, inasmuch as that was the peak load on which the models were based. That in our view does not excuse the Company for knowingly contracting for excessive forward purchases, as stated

---

electricity market, the exercise of market power by generation owners, and inept regulation." (pg. 21) With respect to the criticism leveled against the spot market, the authors go on to note that "One element that has been widely identified as a problem in the [California] market rules is 'over reliance on the spot market' resulting from a 'prohibition' on forward contracting. Apparently the FERC believed, when it issued its December 15 order…that the system was 100% reliant on the spot market. This was never the case since prices paid for utility-owned generation and QFs were determined by regulatory side agreements. Also, as noted earlier, the PX [the California Power Exchange, i.e., the spot market] had a forward market that opened in 1999. The utility distribution companies could purchase 20% of their requirements in the PX forward market with recovery of the cost guaranteed by the CPUC [California Public Utilities Commission]; The utilities were not prohibited from making forward purchases in excess of 20%, but the recovery was not guaranteed by the CPUC." (pgs. 24-25)

[89] As noted above, the Company's hedge target for the month of July 2000 was 124% of gross peak load (load not reduced by committed supply) and 151% of net peak load after deducting committed supply.

above by its consultant in reference to the July 2000 hedge targets, but simply raises the question as to why the single hourly peak load was used for hedging purposes rather than the average. Forward contracts sized on the hourly peak load *guarantee* that there will be substantial amounts of excess energy not utilizable in the remaining on peak hours, and beyond a fleeting reference to risk management theory in a footnote, the Company did not provide any justification for its use of the peak hourly load as opposed to the average, most importantly from a cost standpoint. Staff's analysis on the other hand, and the Auditors' to a lesser extent, show that the Company's on peak energy purchases were demonstrably excessive, and imprudently increased its BGS costs in the periods analyzed.

<u>"After-the-Fact" Performance Reviews and PJM Benchmark</u>

In opposing the use of external benchmarks in general, and the PJM spot market in particular to measure the cost-effectiveness of its BGS procurement, the Company maintains that only the adequacy and execution of its procurement plan itself -- its management, policies and procedures, models and other tools, staffing, training and the like, are relevant to the Board's prudency determination in this proceeding. On that basis the Company asserts that its BGS procurement during the first three years of the transition period was reasonable and prudent, and that the Auditors have, with minor exceptions, concurred in this assessment.

While not denying that the criteria cited by the Company are important, and while also recognizing that an after-the-fact review is vulnerable to the charge of Monday morning quarterbacking, the Advocate and Staff nonetheless maintain that it is equally important to consider the *results* of the Company's BGS procurement, both during the transition period as it unfolded, and in performing this post-transition prudency review required by the Final Restructuring Order. A results oriented review in turn necessarily requires the establishment of a benchmark against which the results are to be measured.

As to the Company's failure to periodically review its performance during the transition period, the Advocate asserts that such reviews were essential to assessing the effectiveness of the Company's procurement plan and for implementing needed modifications when indicated: "The Company should have been conducting after-the-fact comparisons throughout the BGS procurement period because information on the performance of a strategy is vital to determination of whether the strategy should be continued. If every transaction of a particular type that JCP&L made turned out to be uneconomic, prudent management would require that the use of that type of transaction be re-examined, restricted or stopped entirely." (R-59 at 32, 3 to 16)

While the Brattle Group reviewed the Company's procurement experience over the eight-month period from December 1999 through July 2000, that review did not have as its focus how the Company was doing compared to an appropriate external benchmark, <u>i.e.</u>, the PJM spot market. Instead, the cost of the Company's forward purchases was compared to the slightly lower cost that assertedly would have resulted if the dollar cost averaging recommended by the Brattle Group had been employed during the period reviewed. As discussed above, a comparison to PJM prices over the period indicated that the cost of the Company's purchases was more than twice the cost of the equivalent energy if purchased from PJM. A simple analysis of the reasons for the difference in turn revealed that of the $82 million total difference, excess energy purchases – purchases known to be in excess of the Company's requirements before the fact and not the result of forecast error – accounted for $53 million. This analysis, Staff maintains, should have been performed, and should have triggered a review and modification of the Company's models to eliminate the possibility of purchasing forward energy in excess of the Company's projected requirements. One possible modification suggested by Staff would have been to increase reliance on spot market purchases from PJM. Another modification suggested by the Company's explanation of the reason for the excess purchases in its Reply Brief would have been to change from the single hourly peak load to the monthly average as the basis for establishing the hedge targets for the delivery months.

The Auditors' retrospective review of the Company's forward purchases for the summer months of 2001 also found that it had incurred excessive BGS costs due in part to excess forward energy purchases for those months. Thus a second opportunity to potentially modify the Company's procurement methods and models was missed due to its failure, in this instance, to have performed any retrospective review of its performance in these important months at all.

More generally, based on data supplied by the Company, Staff compared the cost of the discretionary component of the Company's BGS procurement over the first three years of the transition period to the "default option" of purchasing the same energy and capacity from PJM, and found that if priced at the PJM prices experienced during the period, the cost of the discretionary purchases would have been $329 million lower than the actual cost of the Company's purchases. The Company and the Auditors assert that such a comparison is flawed because it assumes PJM prices would not have changed as a result of the Company's (and its affiliates') increased PJM purchases. The Company avers that due to the increased demand, PJM prices would have increased, and while the Auditors did not state that prices would have increased, they maintained that in any event they would have been different. Staff on the other hand argues that the increased supply in the absence of the Company's forward purchases would have exerted downward pressure on PJM prices. Moreover, by avoiding the risk premiums imposed on forward purchases, the Company would have enjoyed an additional benefit. Although not noted by Staff, by purchasing in real time, the Company would also have avoided the losses incurred on the resale of the excess forward energy noted above, as well as potential additional losses attributable to forecast error.

We agree with Staff and the Advocate that the Company should have been periodically reviewing and benchmarking its performance during the transition period for the reasons cited by the Advocate. We also find the use a benchmark for assessing the cost-effectiveness of the Company's procurement over the first three years of the transition period to be appropriate, indeed the only way of quantifying a finding of imprudence, a point recognized by the Auditors.[90] We additionally find the cost of energy and capacity purchased from the PJM spot market, the default option, as Staff puts it, to be appropriate for that purpose. As to the question of whether PJM prices would have increased as a result of the Company's increased spot purchases, as maintained by the Company, or decreased due to the increased supply no longer sold forward, as suggested by Staff, a computer simulation of the PJM spot market, both with and without the increased purchases and forward supply, may have shed additional light on this issue. However, in the absence of such a simulation or other record evidence that

[90] At the hearing on April 28, 2003 (13T 80-5 to 80-10) subject to possible adjustment to reflect the factors discussed on the preceding pages of the transcript.

would support the Company's contention, we find Staff's argument both plausible and persuasive, i.e., that the supply no longer devoted to fulfilling the Company's forward contracts would have instead been marketed in PJM, which, if all else remained equal, would have acted to reduce prices. More probable in our view, however, is Staff's contention that in all likelihood this increased supply would simply have been purchased by the Company. That is, we find plausible Staff's observation that the Company would in all probability have obtained the same output from the same facilities, only via the market mechanism of PJM in contrast to contractual purchases in the forward market.

Having said that, we also recognize that it was reasonable for the Company to have hedged a portion of its BGS requirement, and that it could have incurred increased costs as a result of such hedging. Moreover, this possibility was also recognized by the Final Restructuring Order. However, even assuming a hedge premium over spot as high as 23%, the average ratio of forward to spot prices determinable from Mr. Graves testimony,[91] the Company still paid about $144 million more than it should have, in that the actual cost of its discretionary purchases exceeded the cost of equivalent PJM purchases by 41%, a clearly excessive premium in our view.[92] We also note that the $144 million difference is reasonably close to the disallowance recommended by Staff. As a final check on the reasonableness of the PJM benchmark, we note that the energy and capacity component of the year four auction price, at approximately 4.29[93] cents per kwh was close to the 4.25 cents on which Staff's recommended disallowance is based.

Inadequate Documentation and Inconsistency of Model Application

In asserting that the Company's modeling process was seriously flawed, the Advocate maintained that the Company shifted strategies frequently in a comparatively short period of time and failed to implement even the most basic review and control measures. (RIB at 7-8). Moreover, the Advocate found the X-method to be flawed in that it did not seek to minimize costs and was applied in a manner inconsistent with its initially stated approach. (Id. at 12-15). The Advocate additionally maintained that the HOST model was run using risk tolerances not supported by the Company's own consultants and without clear direction as to target levels, nor, the Advocate asserted, did the Company adequately review model inputs crucial to the determination as to whether the model was effective. (Id. at 16-20).

After giving consideration to all of the above, we **HEREBY FIND** as follows:

1. The objective of the Company's models, minimizing the effect of BGS procurement on pre-tax earnings and the volatility thereof, was inappropriate for application in New Jersey;

2. In both instances analyzed in detail by Staff and the Auditors, excess forward purchases, a flaw apparently permitted by the Company's models, increased

[91] By comparing the average forward on-peak price ($46.76 per Mwh) calculated from Mr. Graves' Revised Exhibit FCG-8 to the average on-peak spot price calculated from that exhibit ($37.95 per Mwh).

[92] $144 million = $796 million from Table 1 times (0.413-0.232).

[93] 4.865 cents per kwh less 0.2 cents per kwh for ancillary services and 0.375 cents per kwh for transmission.

its BGS costs. To have knowingly committed to such purchases before the fact was patently imprudent;

3. The Company's failure to perform after-the-fact analyses of its BGS procurement performance during the transition period was imprudent;

4. The Company's documentation of its procurement decisions during the transition period was inadequate. Of particular concern is the Company's failure to keep records of how many bids it received, who the bidders were, and the prices they bid when the Company entered into its forward contracts;

5. The Company's employment of its various models during the transition period was so difficult to follow as to support the Advocate's assertion that the models were haphazardly and inconsistently applied; and

6. PJM energy and capacity prices experienced during the transition period are an appropriate benchmark for quantifying the effect of the Company's imprudence.

Accordingly, after reflecting estimated savings of $176.5 million achieved from the Company's TPPAs and the restructuring of its PPA with the Bayonne NUG project, we **HEREBY DISALLOW** $152.5 million of the Company's BGS costs incurred during the three year period ended July 31, 2002.

B. RETURN ON PRE-DIVESTITURE GENERATION INVESTMENT

Staff, the Advocate and the Auditors have questioned the Company's use of a 14.64% rate in calculating the return component of the revenue requirement of its fossil units and TMI-1 prior to divestiture. As noted above, except for Yards Creek and the Forked River turbines, which the Company continues to own, the fossil units were sold to Sithe in October 1998, and the sale closed in November 1999. Similarly, TMI-1 was sold to AmerGen in October 1998 and the sale closed in December 1999. The 14.64% pre-tax rate of return was accordingly applied to the Company's investment in these units during the period from August 1999 through the sale closing dates, and on its investment in Yards Creek and the Forked River units from August 1999 through July 31, 2003, the end of the transition period.

In the absence of a Board Order specifying the rate to be used, the Company employed the overall rate of return assumed in performing its cost of service study in the restructuring proceedings (14.64% pre-tax). Staff maintains this rate was effectively superseded by the 9.5% overall rate of return on which the reduction in the Company's average distribution rate from 3.70 cents per kwh to 3.45 cents was based.

We agree with Staff that the 9.5% rate of return effectively superseded the rate on which the Company's 1996 cost of service study was based, as indicated by the clear language of the Final Restructuring Order at 93:

> GPU has maintained in this proceeding that the 1996 COSS reflected in Schedule MRK-6 supports [an] average distribution rate of 3.70 cents. Nonetheless, it has agreed, as part of

> Stipulation 1, to an average distribution rate of 3.45 cents. The Board considers this reduction to be reflective, among other things, of a reduction in the distribution revenue requirements to reflect a more current overall cost of capital of 9.5%, which was supported by the RPA and other parties.

Accordingly, we **HEREBY ORDER** the Company to recalculate the return component of the pre-divestiture revenue requirement of the fossil units and TMI-1, as well as Yards Creek and the Forked River turbines, during the transition period to reflect the pre-tax equivalent of the 9.5% overall rate of return, and for that purpose the Company shall employ the methodology employed by Atlantic Electric.[94] Effective August 1, 2003, the return component of the revenue requirement of Yards Creek and the Forked River CTs shall be further adjusted to reflect our return finding in this proceeding (11.41% pre-tax, based on an overall rate of return of 8.38%, including an allowed rate of return on common equity of 9.50%).[95]

C. Mitigation Of Above-Market NUG Costs

As indicated above, the Ratepayer Advocate's witness Chernick asserts that the Company had failed to demonstrate any management of its NUG contracts to minimize NUG costs. (R-59 at 32-22 to 33-2) The Advocate expanded on this contention in its Initial Brief, asserting that the Company had "achieved no significant mitigation of NUG contract costs since 1997,"[96] (RIB at 31) and in particular, had failed to mitigate the above market costs of its three most expensive contracts, those with the South River, Lakewood and Bayonne projects having projected above-market costs during the transition period of $250 million, $114 million and $184 million, respectively. (Id. at 29-30) The Advocate also took issue with the Company's handling of the Reliant Proposal and for not mitigating the above market costs of its smaller NUG contracts more aggressively, as found by the Auditors. Accordingly, the Advocate proposed disallowing interest on the above-market NUG cost component of the Company's deferred balance, which it calculated to be $59.5 million. (Id. at 31; Schedule 2).

In its Reply Brief the Company faulted the Advocate for proposing a disallowance of this size for the first time in its Initial Brief, and for that reason alone (i.e., on procedural grounds) maintained that it should be dismissed. (CIB at 101). In support of its mitigation efforts the Company cited the Auditors' finding that "JCP&L has maintained a reasonable and prudent program for NUG mitigation since well before the [Board's 1993] *Towner* Order [Decision and Order dated April 12, 1993, in Docket No. EM91040844]" and, with limited exceptions not here relevant, has "prudently implemented its mitigation

---

[94] Calculating the return quarterly, based on the actual weighted average embedded cost of debt and preferred, and a residual weighted average equity return determined by deducting the weighted debt and preferred costs from 9.5% and grossing up the residual equity return for income taxes. The investment in the generating units to which the pre-tax return is applied is also to be reduced to reflect monthly depreciation charges.

[95] SIB at 20, with a 9.50% rate of return on common equity.

[96] i.e., beyond the $6.3 million of savings achieved through the third quarter of 2002 from negotiating interim operating agreements with the Parlin and Newark Boxboard projects in March 2001. (RIB at 28).

program." (Id. at 102). In further support of the reasonableness of its mitigation efforts the Company cited the rebuttal testimony of witness Mascari, who reviewed the Company's continuing and previous mitigation efforts that began in the early 1990's, as evidenced by the pre-construction buyouts of the American Ref-fuel, Crown/Vista and Freehold PPAs, thereby achieving estimated ratepayer savings of $620 million on a net present value ("NPV") basis over the life of the terminated contracts. (JC-14 Rebuttal at 23-5 to 25-12) More recently, the Company negotiated pricing concessions from other project owners totaling approximately $60 million on the same NPV basis, and received an upfront payment of $25.4 million in return for negotiating revised pricing of the PPA with the Bayonne project. Id. That payment in turn was credited to the deferred balance in December 2002. (CRB at 102). Moreover, the Company files a quarterly report with the Board and the Advocate that provides the status of ongoing negotiations with each project owner as of the end of that quarter.[97]

As indicated above, the Auditors provided a comprehensive review of the history and results of the Company's NUG mitigation efforts in Chapter VIII of the Phase I Audit Report (S-38). While finding that the Company's mitigation efforts had complied with the Board's filing requirements, and that the Company for the most part had maintained a reasonable and prudent program for NUG mitigation since well before the Board's *Towner* Order, at least for its larger projects, the Auditors did conclude that the Company was less than aggressive in pursuing mitigation opportunities for the Camden, Gloucester and Kenilworth projects aggregating 50 Mw of contract capacity, and accounting for approximately $48 million of total above-market NUG costs of $770 million estimated for the period 2000-2003. (Id. at VIII-9, VIII-13; Exhibit VIII-2) Should the Board find that a disallowance related to these less than aggressive efforts was warranted, the Auditors suggested quantifying the disallowance at 10% of the contract payments made to the three NUGs during the transition period, or $5.6 million.[98] The 10% was assertedly the savings target internally set by the Company for its restructuring efforts. (Id. at VIII-16) As part of the Phase II Audit the Auditors also recommended re-examining the Company's rejection of a comprehensive NUG contract restructuring proposal made by Reliant Energy, and also investigating the reason for the delay in the receipt of the Bayonne PPA restructuring payment. (Id. at VIII-15)

In Supplemental Rebuttal Testimony filed on April 21, 2003, Mr. Mascari pointed out that the 10% savings target applied only to the above-market component of the NUG contract payments, not the entire amount, and if the 8% savings percentage actually achieved in restructuring the pricing terms of the Bayonne PPA were applied to the Camden, Gloucester and Kenilworth above market contracts payments, the disallowance suggested by the Auditors would be reduced to $2.4 million. (JC-14 Supplemental Rebuttal at 18-3 to 19-17)

Moreover, Mr. Mascari asserted that the Company had appropriately prioritized its NUG mitigation efforts in view of the uniqueness of the Camden and Gloucester projects, both of which are resource recovery facilities either owned, financed or subject to approvals by governmental entities (including the New Jersey Department of Environmental Protection) that complicate the negotiation process. (Id. at 20 to 21) The electric output of the Kenilworth project, a 15 Mw qualifying facility, has been limited to 5 Mw due to

[97] As directed by the Board in the Merger Order (its October 9, 2001 Order in Docket No. EM00110870 approving the GPU/First Energy merger).

[98] Corrected to $5.7 million at the hearing on April 28, 2003. (13T 29-2 to 7; Exhibit S-40)

increased steam host demand, and would therefore yield minimal savings from a contract renegotiation. Id.

Staff found the Company's arguments for not accepting the suggested disallowance proposed by the Auditors convincing. With respect to the delay in the closing of the Bayonne PPA restructuring and the Company's rejection of the Reliant proposal, however, Staff agreed that both should be investigated further in Phase II of the audit. Staff also noted that in addition to mitigating NUG costs through buyouts or buydowns of the related PPAs, the Final Restructuring Order directed the Company to maximize the value of NUG contract power either through market sales, or by devoting it to BGS supply:

> GPU [JCP&L] has an ongoing obligation to take all reasonable measures to mitigate the stranded costs associated with NUG utility Purchase Power Agreements, including optimizing the market revenues received for the sale of power and other marketable services derived from the Purchase Power Agreements on the open market, or for use of Non-Utility Generator and Utility Purchase Power Agreement power to offset purchases of energy and capacity or other services otherwise necessary to serve Basic Generation Service customers…
>
> [Final Restructuring Order at 109, paragraph 22]

In view of this requirement, and the possibility that using NUG energy to supply BGS could provide greater value than reselling the NUG energy to PJM,[99] and to monitor and assess the value received from the resale of the NUG energy on an ongoing basis, Staff recommends that in addition to the quarterly reporting requirement previously ordered by the Board, that the Company be directed to file monthly reports that show, for each NUG project, the energy and capacity purchased (Mwh and Mw), the amount paid for the energy and capacity, the disposition of the energy and capacity (i.e., whether it was resold in the wholesale market or otherwise), the amount received from the sale of the energy and capacity, as well as the value of the energy if it were priced at the average monthly PJM LMP and capacity deficiency rate, and the value if it were priced at the rate payable for BGS supply obtained pursuant to the statewide auction.

In accepting this recommendation of Staff, as well as its extension to Yards Creek and the Forked River CTs, we incorporated this identical language in the Summary Order (at 16-17). Upon further review, we **HEREBY MODIFY** this directive to 1) add the phrase "for the zone in which JCP&L operates" after "LMP;" and 2) to replace "capacity deficiency rate" with "the average rate at which capacity sales were transacted during the month;" and 3) to replace "rate payable for BGS supply obtained pursuant to the statewide auction" with the "energy and capacity component of the rate payable for BGS supply obtained pursuant to the statewide auction, or if not known precisely, a reasonable estimate thereof." The Company accordingly is directed to implement this

[99] Staff also cited this possibility for the output of Yards Creek and the Forked River CTs.

change going forward, and to provide revised versions of the reports previously supplied in response to the Summary Order to reflect this change.

Additionally, with respect to Yards Creek and the Forked River CTs, we **HEREBY DIRECT** the Company to include, as part of its Phase II filing in this proceeding, an economic study that addresses the "best use" of these facilities for the benefit of ratepayers. Such a study should examine whether the units should be divested or retained, and, as suggested above, if and while retained, there is a more advantageous use of the output of the units than reselling their energy and capacity at wholesale. Also to be included in the study is a proposal for the ratemaking treatment to be accorded the units in the event they were to be retained.

With respect to the Advocate's proposed interest disallowance, and while noting that the Company has been less than aggressive than PSE&G in mitigating the above market costs of it NUG contracts, we, like Staff and the Auditors, do not believe that the Company's efforts warrant the disallowance recommended by the Advocate. We also note that following the restructuring of the Bayonne contract, the Company successfully restructured its PPA with North Jersey Energy Associates for the purchase of energy and capacity from the South River (Sayreville) project with attendant NPV savings estimated to be in excess of $50 million.[100] The Company has also restructured its PPAs with Calpine Newark, LLC and Calpine Parlin, LLC, as well as the agreement for the gas supply for these projects. As a result it received an upfront payment of $52.8 million associated with the re-negotiated PPAs, which is to be credited to the MTC deferred balance, net of reasonably and prudently incurred transaction costs. Additionally, PSE&G is to credit a $22 million payment it received as a result of the renegotiation of the gas contract to the benefit of its gas customers.[101]

Finally, with respect to the small projects, we agree with Staff that the Company appropriately prioritized its mitigation efforts, that these projects appear to involve complicating factors not present with the other projects, and that the resultant savings, if any, would not be significant relative to those potentially achievable from re-negotiating the PPAs with the larger projects. Accordingly, we **HEREBY REJECT** the disallowance suggested by the Auditors.

D. SBC DEFERRED BALANCE/CHARGES

(1) Nuclear Decommissioning Funding

[100] I/M/O the Application of Jersey Central Power & Light Company for the Approval of an Amendment and Restatement of the Power Purchase Agreement Currently Existing Between it and North Jersey Energy Associates, a Limited Partnership, Docket No. EM03060438, Order dated November 5, 2003.

[101] I/M/O the Application of Jersey Central Power & Light Company for the Approval of the Termination of the Power Purchase Agreements Currently Existing Between it and Calpine Newark, LLC and Calpine Parlin, LLC and the Execution of a New Power Purchase Agreement with CES Marketing II, LLC or its Designee and I/M/O the Application of Public Service Electric and Gas Company for the Approval of an Amendment to the Gas Service Agreement Currently Existing Between it and Jersey Central Power & Light Company Docket No. EM04010045, Order dated March 24, 2004.

In its Reply Brief at 113 the Company accepted Staff's recommended reduction in the carrying costs applicable to the unamortized balance of the Oyster Creek top-off payment to reflect the Board's rate of return finding in the Company's base rate case, and we **HEREBY ORDER** such carrying costs to be so reduced. As indicated in the Summary Order, the reduction amounts to approximately $3.3 million per year. The Company also indicated in its Reply Brief that it had corrected its claimed amortization of the TMI-1 top-off payment to eliminate carrying costs, which were not authorized by the Board's Order approving the TMI-1 sale. Additionally, the Company asserted that its proposed revision in TMI-2 decommissioning funding was simply an update to reflect changes in inflation and earnings rates, and the remaining balance to be amortized. (Id.). On that basis, we **HEREBY APPROVE** the annual amounts shown in Schedule MJF-8 ("12+0" Update) included in Exhibit JC-75 of $2.1 million and $2.9 million for TMI-1 and TMI-2, respectively.

With respect to Saxton, the Company argues, in its Reply Brief, that the fact that the ratepayers of the Company's affiliates in Pennsylvania are no longer funding the cost of decommissioning this facility is not a basis for terminating funding on the part of New Jersey ratepayers. (Id. at 114-115). We disagree, finding no basis for continuing an unbalanced regulatory treatment at the expense of New Jersey ratepayers, an imbalance we find already excessive, as evidenced by the disparity in accumulated funding shown in Exhibit S-6, i.e., a JCP&L Saxton trust fund balance as of December 31, 2002 of $0.5 million as compared to less than $5,000 for the Pennsylvania companies combined. Accordingly, we **HEREBY DISALLOW** the Company's claimed Saxton decommissioning funding of $0.6 million annually.

While not as pronounced, Exhibit S-6 also shows a similar disparity between the trust fund balances accumulated by the three utilities as of December 31, 2002 for the eventual cost of decommissioning TMI-2 ($106.3 million, $155.7 million and $88.8 million for JCP&L, Met-Ed and Penelec, respectively). Moreover the Company indicates in S-6 that funding of TMI-2 decommissioning costs by Penelec's ratepayers has ceased, and that funding by Met-Ed's ratepayers (at the rate of $9.5 million per year) will cease in the year 2010. We believe this apparent disparity, particularly the difference between the trust fund balances of the Company and Penelec, each of which owns 25% of TMI-2, warrants further review, and accordingly will direct the Company to address why TMI-2 decommissioning funding by New Jersey ratepayers should be continued at its current level as an issue in its January 1, 2004 filing pursuant to N.J.A.C. 14:5A.[102]

(2) Universal Service Fund (USF)

Since the implementation of the appropriate USF charge was not to occur before August 1, 2003, JCP&L proposed to defer recovery of its costs, including interest, to implement the permanent USF program until after the Company receives the Board Order in the pending USF proceeding. Neither the RPA nor Staff addressed this issue.

Pursuant to the Board's July 16, 2003 Order I/M/O the Establishment of a Universal Service Fund Pursuant to Section 12 of the EDECA of 1999, Docket No. EX0002009,

[102] By Order issued on April 28, 2004, the Company was directed to address this as well as other TMI-2 decommissioning issues in Docket No. EO03121014, I/M/O the Request of Jersey Central Power & Light Company for a Waiver of Filing Requirements Under N.J.A.C. 14:5A, Nuclear Plant Decommissioning Cost and Trust Fund Review.

the Board **HEREBY AUTHORIZES** the Company to include $22.0 million of such costs in the SBC.

(3) Demand Side Management (DSM)

JCP&L recovers its regulated DSM costs through the SBC. The Company requests an annual recovery of $38.8 million, resulting in a decrease in its DSM of over $15 million. The RPA did not oppose the Company's request, but did address the Company's request for lost revenues as part of the Company's energy efficiency programs. Staff did not oppose the Company's request.

Based upon the record in this matter, the Board **HEREBY ADOPTS** the Company's proposal to reflect a reduction in the Company's annual recovery of DSM costs, i.e., Clean Energy Program costs, in the amount of $15.0 million.

(4) Consumer Education (CED)

The Company proposes to recover all Board approved costs associated with the CED, along with any carrying charges, beginning August 1, 2003. The Company estimates that the CED costs will total approximately $5.6 million and proposes to recover these costs through a base charge of 0.0278 cents per kwh.

The RPA would disallow any recovery by the Company of its CED costs for Year 2 and Year 3. The RPA believes that the statewide CED failed to achieve its goals of increasing awareness among gas and electric consumers in the critical areas of energy competition, alternate energy suppliers, energy conservation and efficiency, and the availability of financial assistance to eligible consumers.

Staff believes the Company is entitled to recover its costs associated with the CED and agrees with the Company's proposed CED Tariff Rider of 0.0278 cents per kwh.

The Consumer Education program was a statewide effort jointly funded by all of the State's electric and gas utilities. M&T, the Board's independent auditors, audited the CED deferred balance through July 31, 2002 and noted no material non-compliance issues with JCP&L's accounting of the rate recovery or recording of expenses related to this SBC component. The Board **HEREBY ADOPTS** the Company's proposal, as supported by Staff, and **HEREBY APPROVES** JCP&L's recovery of these CED costs.

E. INTERIM RECOVERY OF DEFERRED BALANCES

Staff, the Advocate and the Company all note that while the Board has reserved for decision in the Company's pending securitization proceeding[103] the issues as to whether all or some portion of the Company's deferred balances (i.e., its BGS and MTC balances) should be amortized or securitized, and over what period and at what rate, the Board did not preclude the parties from making proposals for the interim recovery of the balances in this proceeding pending the Board's final decision. Accordingly, based on

[103] The Company's securitization petition in Docket No. ER03020133 was filed on February 14, 2003, and amended on September 19, 2003 to reflect the Board's disallowance of $152.5 million of BGS deferrals. A second amendment was filed on December 1, 2003. Discovery has been issued and responded to, and the Advocate's testimony was filed on January 16, 2004.

the testimony of its witness Rothschild (R-49) the Advocate proposed amortizing the Company's deferred balances over a 10-year period at the rate on 7-year treasury notes plus 60 basis points, the rate previously authorized by the Board on deferrals incurred during the transition period. Moreover, the recovery should be "net of tax." (RIB at 74-79). The Company on the other hand argues for a four-year recovery at the 7-year treasury rate, or alternatively, an amortization period of more than four years but less than ten, with interest at the Company's overall weighted average cost of capital. (CIB at 193) Staff, like the Advocate, proposes net-of-tax recovery over ten years, but at the rate on 1-year treasuries plus 30 basis points. Staff maintains that this rate is appropriate on the expectation that the interim recovery will be in effect for at most a matter of months.

Given the rate impact of four-year recovery (at 12.4%, more than double the 6.1% increase estimated by the Company assuming its requested "12+0" base rate increase were granted in full and its deferred balances securitized over 15 years at 5% interest), we believe the 10-year amortization period recommended by the Advocate and Staff to be appropriate for interim deferral recovery. Moreover, given today's historically low interest rates, which are expected to remain so near term, we also believe the interest rate recommended by Staff will fully compensate the Company for the carrying costs incurred pending our final decision in the securitization proceeding. Accordingly, we **HEREBY APPROVE** the interim deferral recovery proposed by Staff. As reported in the Company's deferred balance report filed with the Board on June 30, 2003, reflecting actual data through May 2003, the Company's deferred BGS/MTC balance is projected to be $618.0 million, including accrued interest of $40.7 million, as of July 31, 2003. After reflecting the $152.5 million disallowance ordered herein, and subject to the true-up discussed below, the Company's recoverable BGS/MTC balance is $465.5 million, which when amortized net of tax over 10 years at an assumed interest rate of 1.30%[104] yields interim deferral recovery pending the Board's decision on the Company's securitization petition of $48.541 million [105] per year before application of the 6% New Jersey Sales and Use Tax, and $51.453 million with the tax included.

F. INTEREST RATE AND METHOD TO BE APPLIED TO POST-TRANSITION DEFERRALS

We agree with Staff's recommended changes in the rate and methodology for calculating interest on post-transition SBC, BGS and MTC[106] deferrals for the reasons set forth by Staff. While the Company accrued interest on the net of tax balance of deferred costs during the transition period (the deferred balance less the related accumulated deferred income taxes, which effectively reduce the balance to be financed by the amount of the taxes) and at the Board-approved rate (the rate on constant maturity 7-year treasury notes plus 60 basis points), the calculation was performed

---

104 Based on the yield on one-year constant-maturity treasury notes for the week ending June 27, 2003, as reported in the Federal Reserve Statistical Release dated July 1, 2003.

105 $465.5 million divided by 9.58977, an annuity factor with n = 10 and i=0.76895 (1.30%, net of tax).

106 In view of the expiration of the four-year transition period, we believe it appropriate to re-name the MTC the NGC ("non-utility generation charge"), as indicated below.

annually, did not reflect the tax benefit from the interest itself during the deferral period, and was calculated on a “simple interest” basis.

With respect to the rate, because the SBC, BGS and MTC charges will now be revised annually, the use of the Company’s rate on short-term debt (debt due in one year or less, or if no short-term debt is outstanding, the rate on equivalent temporary cash investments) will more accurately reflect the Company’s true cost of borrowings to finance deferrals than would continued use of the 7-year treasury rate. Similarly, the rate on equivalent temporary cash investments appropriately and symmetrically reflects the interest due ratepayers on over-recoveries. We also agree with Staff that it is desirable to standardize the method as well as the rate employed by the Company, Atlantic Electric and RECO,[107] i.e., by calculating interest monthly on the beginning and end average of the balance of deferred costs less the deferred taxes associated with the deferred costs and interest, and by compounding interest annually.[108] Accordingly, we **HEREBY APPROVE** the changes recommended by Staff, and **HEREBY DIRECT** the Company to recalculate the interest accrued on its deferred balances during the transition period to reflect the methodology approved herein, and additionally, to prospectively employ, as the rate applicable to post-transition deferrals, the monthly rate actually incurred on short-term debt, or in the event no short-term debt is outstanding, the rate available on equivalent temporary cash investments.

G. DISCONTINUANCE OF THE MTC AND ITS REPLACEMENT BY THE NGC

Section 13 (C.48:3-61) of the EDECA provides for the imposition of a limited duration, non-bypassable market transition charge for the recovery of generation-related stranded costs, buyouts and buydowns of uneconomic PPAs with other utilities and non-utility generators, and restructuring costs approved by the Board. Unless extended by the Board to recover above-market payments under PPAs with NUGs over the terms of the PPAs, or the costs of a specific generating asset comprising at least 20% of the utility’s stranded costs, or to achieve the rate reductions mandated by the EDECA, the term of the MTC is not to exceed eight years. For the Company (as well as the state’s other electric utilities), the Board established a four-year period for effecting the transition to a market-based generation supply, and that period is now over. However, the need for an ongoing charge to bill above-market costs associated with NUG PPAs, net of the revenue received from the sale of the NUG energy and capacity in the wholesale power markets, or other employment of the NUG energy and capacity continues. Moreover, at least for now, the generation and the capacity of Yards Creek and the Forked River turbines is also being sold in the wholesale power markets, with the revenue received from such sales, net of the units’ revenue requirement, credited to above market NUG costs.

---

[107] The PSE&G Settlement approved by the Board provided for a similar change in post-transition interest accruals.

[108] As illustrated in Exhibit 2 attached to the Board’s Final Order issued on April 20, 2004 in the deferred balances and base rate proceedings of Rockland Electric Company (I/M/O the Verified Petition of Rockland Electric Company for the Recovery of its Deferred Balances and the Establishment of Non-Delivery Rates Effective August 1, 2003 (Docket No. ER02080614) and I/M/O the Verified Petition of Rockland Electric Company for Approval of Changes in Electric Rates, its Tariff for Electric Service, its Depreciation Rates and for Other Relief (Docket No. ER02100724).

While this treatment could presumably continue for another four years, i.e., if the Board were to authorize a continuation of the Company's MTC as currently constituted for another four years, and if Yards Creek and the Forked River turbines were to be retained that long, the EDECA would not appear to allow the inclusion of these units in an MTC beyond then. Moreover, with the transition period now over, the basis for calling this unbundled rate charge an MTC, i.e., a "market transition charge," no longer applies. Accordingly, we believe it appropriate to discontinue the MTC, and replace it with a non-utility generation charge ("NGC") for the continued recovery of above-market NUG costs, net of the revenue received from the sale of the energy and capacity of the NUGs, and, pending review of this treatment in Phase II of this proceeding, the net revenue requirement of the Company's retained generating units, effective upon the date the Company's unbundled rates (i.e., its unbundled rates other than its distribution charges) are next changed.

VII. SUMMARY OF BOARD FINDINGS, DEFERRED BALANCES

(a) Deferred BGS/MTC Balance

1. After deducting the disallowance of deferred BGS costs of $152.5 million ordered herein from the Company's deferred BGS/MTC balance of $618.0 million projected as of July 31, 2003, including accrued interest of $40.7 million, the Company is **HEREBY AUTHORIZED** to recover a deferred BGS/MTC balance of $465.5 million.

2. This balance shall be trued-up to reflect: 1) actual data through July 31, 2003; 2) the results of the Board-ordered Phase II Audit of the Company's deferred balances; 3) the reduced return on the Company's generating units accrued during the transition period, as directed below; and 4) a re-calculation of accrued interest to reflect the disallowance and these adjustments, as well as the change in the interest rate calculation methodology, also as directed below.

3. For purposes of interim recovery pending the Board's decision on the Company's securitization petition, the recoverable BGS/MTC balance shall be recovered at the rate of $48.541 million per year before application of the 6% New Jersey Sales and Use Tax, and $51.453 million per year with the tax included.

4. With the exception of Oyster Creek, for purposes of determining the revenue requirement of the Company's generating units during the period the energy and capacity of the units was devoted to BGS supply, and the revenue requirement included as part of the costs recoverable by the shopping credit and the MTC, the return component of the revenue requirement shall be recalculated to reflect an overall rate of return of 9.50%, as well as accumulated depreciation from monthly depreciation of the units, as described herein. For Yards Creek and the Forked River CTs, the return component of the revenue requirement shall additionally reflect the rate of return allowed herein (8.38%), effective August 1, 2003.

5. The Company shall supplement its Quarterly NUG Mitigation Reports with the monthly reports ordered herein.

6. The issues of the delayed receipt of the $25.4 million upfront payment from the Bayonne NUG project and why the Reliant Energy NUG PPA restructuring proposal was turned down will continue to be pursued in the Phase II Audit.

7. As part of its Phase II filing in this proceeding, the Company shall include an economic study that, given current and projected conditions in the energy markets, addresses 1) whether it is likely to be better for ratepayers if the Company's interest in Yards Creek and the Forked River CTs are retained or divested; 2) the most economic use of these units while retained (i.e., whether the energy and capacity of the units should be sold in the wholesale power markets or devoted to BGS supply); and 3) the ratemaking treatment to be accorded the units while they are retained. The effect of retaining or divesting the units on the Company shall also be addressed in the study.

8. Effective on the date the Company's non-distribution unbundled rates are next changed, the MTC shall be discontinued and renamed the NGC, which charge shall continue to recover the above-market component of payments made under PPAs with non-utility generators (the PPA payments less the revenue received from the sale of the NUG energy and capacity), as well as the revenue requirement of Yards Creek and the Forked River CTs, net of the revenue received from the sale of the capacity and energy from these units, while they are retained.

(b) <u>SBC Deferred Balance/Charges</u>

1. Subject to the Phase II Audit of the Company's deferred balances, the Board **<u>HEREBY</u> <u>APPROVES</u>** the Company's proposed changes in its charges for DSM/Clean Energy program costs (a reduction of $15.0 million), and Consumer Education (CEP) costs (an increase of $5.6 million).

2. Pursuant to the Board's July Order in Docket No. EX0002009, <u>I/M/O the Establishment of a Universal Service Fund Pursuant to Section 12 of the Electric Discount and Energy Competition Act of 1999</u>, the Board **<u>HEREBY</u> <u>AUTHORIZES</u>** the Company to include $22.0 million of USF costs in the SBC.

3. With respect to the nuclear decommissioning component of the SBC, the Board 1) **<u>HEREBY</u> <u>DISALLOWS</u>** the $0.6 million of annual funding claimed by the Company for Saxton; 2) **<u>HEREBY</u> <u>APPROVES</u>** the Company's proposed reduction in the recovery of the TMI-1 top-off payment from $5.2 million to $2.1 million per year, without carrying costs, through August 2009; 3) **<u>HEREBY</u> <u>APPROVES</u>** a reduction in the Oyster Creek top-off payment from $18.2 million to $14.9 million per year through August 2009 to reflect the rate of return allowed in this proceeding, and 4) **<u>HEREBY</u> <u>APPROVES</u>** decommissioning funding of $2.9 million per year for TMI-2, pending a further review of the justification for continuing this level of funding and other TMI-2

decommissioning issues in Docket No. EO03121014, I/M/O the Request of Jersey Central Power & Light Company for a Waiver of Filing Requirements under N.J.A.C. 14:5A, Nuclear Plant Decommissioning Cost and Trust Fund Review.

(c) Interest Calculation

1. The Board **HEREBY DIRECTS** the Company to re-calculate its interest accruals during the transition period to reflect 1) the deduction of deferred income taxes associated with deferred interest as well as the deferred income taxes associated with the deferred costs from the balance on which interest is accrued; 2) a monthly calculation based on the beginning and end average monthly balance, as opposed to an annual calculation; and 3) annual compounding.

2. For post-transition deferrals, i.e., effective August 1, 2003, the method of calculating interest on the Company's BGS, SBC and MTC/NGC deferrals shall be as described in 1) above, but the interest rate shall be reduced from the yield on constant maturity 7-year treasury notes plus 60 basis points to the average rate on the Company's short-term debt outstanding (debt due in one year or less), or in the event that no short-term debt is outstanding, to the rate on equivalent temporary cash investments, determined monthly.

(d) Deferred Accounting

1. The Board **HEREBY APPROVES** continued use of deferred accounting for under and over recoveries of costs recoverable by the SBC and MTC/NGC, as well as for under and over recoveries of costs incurred in supplying BGS, all of which such under and over recoveries shall be recorded as regulatory assets and liabilities on the balance sheet.

VIII. EFFECT OF ALL RATE CHANGES

In addition to reflecting the base rate reduction, the interim recovery of the deferred BGS/MTC balance, the revised components of the SBC, as well as the expiration of the Year 4 EDECA rate reduction, all as provided herein, the Company will implement an increase in its BGS charges effective August 1, 2003 to reflect the results of the statewide auction previously approved by the Board by Order in Docket No. EX01110754 dated February 6, 2003. For customers taking BGS service, the Company estimates that the overall BGS increase, assuming no change for BGS-HEP hourly energy charges, will be about 7.3%, which when combined with the base rate reduction of approximately 11.2%, and an increase of about 8.2% as the combined effect of the deferral case rate changes and the expiration of the EDECA discount, will result in an average increase of about 4.3% to all customer classes.

For the typical residential customer using 686 kwh per month during the winter and 952 kwh per month during the summer, the provisions of this Final Order result in an average annual increase in rates of approximately 3.5% (from approximately $86.01 per month to approximately $89.07 per month).

DATED: ***MAY 17, 2004***

BOARD OF PUBLIC UTILITIES
BY:

SIGNED

JEANNE M. FOX
PRESIDENT

SIGNED

FREDERICK F. BUTLER
COMMISSIONER

SIGNED

CAROL J. MURPHY
COMMISSIONER

SIGNED

CONNIE O. HUGHES
COMMISSIONER

SIGNED

JACK ALTER
COMMISSIONER

ATTEST:

SIGNED

KRISTI IZZO
SECRETARY

Jersey Central Power and Light Company
BPU Docket No. ER02080506
OAL Docket No. PUC7984-02

Schedule Board-1*
Additional Revenues to Achieve Return
($1,000)

Line No.		Petitioner	adjustment	Ratepayer Advocate	adjustment	Staff	adjustment
1	Rate Base	2,053,575	(138,700)	1,914,875	(37,276)	2,016,299	(37,276)
2	Rate of Return	10.05%	-1.97%	8.08%	-1.55%	8.50%	-1.67%
3	Required Operating Income	206,384	(51,662)	154,722	(34,999)	171,385	(37,418)
4	Pro Forma Operating Income	230,928	72,296	303,224	69,682	300,610	69,507
5	Income Deficiency	(24,544)	(123,958)	(148,502)	(104,681)	(129,225)	(106,925)
6	Revenue Factor	1.69062	0.00336	1.69398	0.00336	1.69398	0.00336
7	Revenue Deficiency	(41,494)	(210,065)	(251,560)	(177,410)	(218,904)	(181,212)
8	Applicable Taxes on Revenue Deficiency:						
9	Taxes Other Than Income (Line 7 x Effective Tax Rate of 0.00%)	0					
10	State ((Line 7 - Line 9) x Effective Tax Rate of 9%)	($3,734)					
11	Federal (((Line 7-Line 9)-Line 10) x Effective Tax Rate of 35%)	(13,216)					
12	Total Taxes on Revenue Deficiency	(16,950)					
13	Effect on Operating Income	(24,544)					

***Differences due to rounding.**

Jersey Central Power and Light Company
BPU Docket No. ER02080506
OAL Docket No. PUC7984-02

Schedule Board-2
Rate Base @ 12/31/2002
($1,000)

Line No.		Petitioner	adjustments	Ratepayer Advocate	adjustments	Staff	adjustments	Board
1	Total Electric Utility Plant in Service	3,397,395	0	3,397,395	0	3,397,395	0	3,397,395
	Additions:							
2	Deferred Taxes --TMI -2 Non-Qualified Decommissioning Trust Fund	11,314	0	11,314	0	11,314	0	11,314
3	Total Additions	3,408,709	0	3,408,709	0	3,408,709	0	3,408,709
	Deductions:							
4	Accumulated Deferred Income Taxes	261,874	0	261,874	0	261,874	0	261,874
5	Accumulated Provision for Depreciation	1,319,563	0	1,319,563	0	1,319,563	0	1,319,563
6	Customer Advances for Construction (Net of Tax)	7,017	0	7,017	0	7,017	0	7,017
7	Unamortized Net Gain/(Loss) on Reacquired Debt	(17,366)	0	(17,366)	0	(17,366)	0	(17,366)
8	Customer Deposits	16,745	0	16,745	0	16,745	0	16,745
9	Operating Reserves (Net of Tax)	8,597	0	8,597	0	8,597	0	8,597
10	Total Deductions	1,596,430	0	1,596,430	0	1,596,430	0	1,596,430
11	Net Investment	1,812,279	0	1,812,279	0	1,812,279	0	1,812,279
12	Working Capital:							
13	Materials & Supplies -- Other than Fuel	22,703	0	22,703	0	22,703	0	22,703
14	Cash Working Capital	218,593	(77,560)	141,033	(376)	218,217	(376)	218,217
15	Total Working Capital	241,296	(77,560)	163,736	(376)	240,920	0	240,920
16	Consolidated Tax Savings	0	(61,140)	(61,140)	(36,900)	(36,900)	(36,900)	(36,900)
17	Net Rate Base	2,053,575	(138,700)	1,914,875	(37,276)	2,016,299	(37,276)	2,016,299

Jersey Central Power and Light Company
BPU Docket No. ER02080506
OAL Docket No. PUC7984-02

Schedule Board-3a

Statement of Pro Forma Operating Income for the Twelve Months Ended 12/31/2002
Normalized and Adjusted to Reflect the Effect of Known and Major Changes and Proposed Rates
($1,000)

Petitioner

Line No.		Actual Ended 12/31/02 Delivery T&D	Normalization Adjustments	Pro Forma Present Rates	Additional Revenues to Achieve Return	Pro Forma Proposed Rates
1	Operating Revenues:					
2	Delivery - Transmission & Distribution (Inc. TEFA)	872,775	(12,382)	860,393	(41,494)	818,899
3	Other Operating	27,838	0	27,838	0	27,838
4	**Total Revenue**	900,613	(12,382)	888,231	(41,494)	846,737
5	Total Operating & Maintenance Exp. Including Labor	226,724	91,380	318,104	0	318,104
6	Depreciation and Amortization	145,523	1,751	147,274	0	147,274
7	Decommissioning	0	0	0	0	0
8	Amortization of Property Taxes	0	0	0	0	0
9	Taxes other than Income Taxes	56,049	8,915	64,964	0	0
10	**Total Operating Expenses**	428,296	102,046	530,342	0	465,378
11	Operating Income Before Income Taxes	472,317	(114,428)	357,889	(41,494)	381,359
12	Income Taxes:					
13	Federal	36,507	(23,769)	12,738	(13,216)	(478)
14	State	8,378	(6,717)	1,661	(3,734)	(2,073)
15	Deferred Income Taxes (Net)	116,113	0	116,113	0	116,113
16	Investment Tax Credit	0	0	0	0	0
17	Amortization of ITC	(3,550)	0	(3,550)	0	(3,550)
18	**Total Income Taxes**	157,448	(30,486)	126,962	(16,950)	110,012
19	**Net Utility Operating Income**	314,869	(83,942)	230,927	(24,544)	206,383

Jersey Central Power and Light Company
BPU Docket No. ER02080506
OAL Docket No. PUC7984-02

Schedule Board-3b
Statement of Pro Forma Operating Income for the Twelve Months Ended 12/31/2002
Normalized and Adjusted to Reflect the Effect of Known and Major Changes and Proposed Rates
($1,000)

Ratepayer Advocate

Line No.		Actual Ended 12/31/02 Delivery T&D	Normalization Adjustments	Pro Forma Present Rates	Additional Revenues to Achieve Return	Pro Forma Proposed Rates
1	Operating Revenues:					
2	Delivery - Transmission & Distribution (Inc. TEFA)	872,775	(12,382)	860,393	5,405	865,798
3	Other Operating	27,838	0	27,838	0	27,838
4	**Total Revenue**	900,613	(12,382)	888,231	5,405	893,636
5	Total Operating & Maintenance Exp. Including Labor	226,724	91,380	318,104	(61,371)	256,733
6	Depreciation and Amortization	145,523	1,751	147,274	(39,398)	107,876
7	Decommissioning	0	0	0	0	0
8	Amortization of Property Taxes	0	0	0	0	0
9	Taxes other than Income Taxes	56,049	8,915	64,964	(8,812)	56,152
10	**Total Operating Expenses**	428,296	102,046	530,342	(109,581)	420,761
11	Operating Income Before Income Taxes	472,317	(114,428)	357,889	114,986	472,875
12	Income Taxes:					
13	Federal	36,507	(23,769)	12,738	33,284	46,022
14	State	8,378	(6,717)	1,661	9,405	11,066
15	Deferred Income Taxes (Net)	116,113	0	116,113	0	116,113
16	Investment Tax Credit	0	0	0	0	0
17	Amortization of ITC	(3,550)	0	(3,550)	0	(3,550)
18	**Total Income Taxes**	157,448	(30,486)	126,962	42,689	169,651
19	**Net Utility Operating Income**	314,869	(83,942)	230,927	72,297	303,224

Jersey Central Power and Light Company
BPU Docket No. ER02080506
OAL Docket No. PUC7984-02

Schedule Board-3c
Statement of Pro Forma Operating Income for the Twelve Months Ended 12/31/2002
Normalized and Adjusted to Reflect the Effect of Known and Major Changes and Proposed Rates
($1,000)

Staff

Line No.		Actual Ended 12/31/02 Delivery T&D	Normalization Adjustments	Pro Forma Present Rates	Additional Revenues to Achieve Return	Pro Forma Proposed Rates
1	Operating Revenues:					
2	Delivery - Transmission & Distribution (Inc. TEFA)	872,775	(12,382)	860,393	5,405	865,798
3	Other Operating	27,838	0	27,838	0	27,838
4	**Total Revenue**	900,613	(12,382)	888,231	5,405	893,636
5	Total Operating & Maintenance Exp. Including Labor	226,724	91,380	318,104	52,446	370,550
6	Depreciation and Amortization	145,523	1,751	147,274	(39,398)	107,876
7	Decommissioning	0	0	0	0	0
8	Amortization of Property Taxes	0	0	0	0	0
9	Taxes other than Income Taxes	56,049	8,915	64,964	(8,812)	56,152
10	**Total Operating Expenses**	428,296	102,046	530,342	(100,656)	534,578
11	Operating Income Before Income Taxes	472,317	(114,428)	357,889	106,061	359,058
12	Income Taxes:					
13	Federal	36,507	(23,769)	12,738	28,363	41,101
14	State	8,378	(6,717)	1,661	8,015	9,676
15	Deferred Income Taxes (Net)	116,113	0	116,113	0	116,113
16	Investment Tax Credit	0	0	0	0	0
17	Amortization of ITC	(3,550)	0	(3,550)	0	(3,550)
18	**Total Income Taxes**	157,448	(30,486)	126,962	36,378	163,340
19	**Net Utility Operating Income**	314,869	(83,942)	230,927	69,683	300,610

Jersey Central Power and Light Company
BPU Docket No. ER02080506
OAL Docket No. PUC7984-02

Schedule Board-3d
Statement of Pro Forma Operating Income for the Twelve Months Ended 12/31/2002
Normalized and Adjusted to Reflect the Effect of Known and Major Changes and Proposed Rates
($1,000)

Board

Line No.		Actual Ended 12/31/02 Delivery T&D	Normalization Adjustments	Pro Forma Present Rates	Additional Revenues to Achieve Return	Pro Forma Proposed Rates
1	Operating Revenues:					
2	Delivery - Transmission & Distribution (Inc. TEFA)	872,775	(12,382)	860,393	5,405	865,798
3	Other Operating	27,838	0	27,838	0	27,838
4	**Total Revenue**	900,613	(12,382)	888,231	5,405	893,636
5	Total Operating & Maintenance Exp. Including Labor	226,724	91,380	318,104	(52,271)	265,833
6	Depreciation and Amortization	145,523	1,751	147,274	(39,398)	107,876
7	Decommissioning	0	0	0	0	0
8	Amortization of Property Taxes	0	0	0	0	0
9	Taxes other than Income Taxes	56,049	8,915	64,964	(8,812)	56,152
10	**Total Operating Expenses**	428,296	102,046	530,342	(100,481)	429,861
11	Operating Income Before Income Taxes	472,317	(114,428)	357,889	105,886	463,775
12	Income Taxes:					
13	Federal	36,507	(23,769)	12,738	28,363	41,101
14	State	8,378	(6,717)	1,661	8,015	9,676
15	Deferred Income Taxes (Net)	116,113	0	116,113	0	116,113
16	Investment Tax Credit	0	0	0	0	0
17	Amortization of ITC	(3,550)	0	(3,550)	0	(3,550)
18	**Total Income Taxes**	157,448	(30,486)	126,962	36,378	163,340
19	**Net Utility Operating Income**	314,869	(83,942)	230,927	69,508	300,435

Board
2,016,299
8.38%
168,966
300,435
(131,469)
1.69398
(222,706)

EXHIBIT 1

JERSEY CENTRAL POWER & LIGHT COMPANY
Cost of BGS Supply by Sources *
3 Years Ended July 31, 2002

	$ Millions	% of Total
Owned Generation Prior to Divestiture **	$ 243	7.9%
Power Purchases:		
TPPAs (TMI-1, Oyster Creek and Sithe)	558	18.2
PJM Spot Market	438	14.3
Two-Party and Bilateral Contracts	1,155	37.6
Utility PPAs at Market ***	15	0.5
NUG PPAs at Market ***	550	17.9
Ancillary Services	98	3.2
Financial Instruments	14	0.4
Total	2, 828	92.1
Total Cost of BGS Supply	$3,071	100.0%
Per Mwh of Net System Requirements	$50.15	
Revenue		
Shopping Credit	$2,498	
Sales for Resale	282	
Total	$2,780	
BGS Deferred Balance at 7/31/02	$291	
Projected Balance as of 7/31/03	$369	

* from Schedule SDM-1A, Exhibit JC-13 (“12+0” Update). Excludes return on and of Oyster Creek investment (treated as a stranded cost).

** includes Yard Creek and the Forked River Combustion Turbines (“CTs”) throughout the period (these units were not divested).

*** valued at the average PJM Locational Marginal Price (“LMP”) and capacity rate; above market component included in the MTC.

JERSEY CENTRAL POWER & LIGHT COMPANY
BGS Disallowance, Discretionary Purchases other Than TPPAs
Three Years Ended July 31, 2002

	Gwh or Avg. Mw	$ Millions	$ per Mwh or Mw-Day	% Incr.
Actual Cost of Discretionary Purchases Other than TPPAs:				
Energy	18,735	$ 974.1	$ 51.99	
Capacity	1,813	151.1	105.35	
Total		1,125.2	60.06	
Cost if Purchased from PJM:				
Energy	18,735	699.9	37.36	
Capacity	1,813	96.3	67.18	
Total		796.2	42.50	
Cost above PJM:				
Energy		274.2	14.63	39.2%
Capacity		54.8	38.17	56.9
Total		$ 329.0	$ 17.56	41.3%

TPPA and Other Offsets:

TMI-1 TPPA	
Energy (3,205 Gwh x ($38.12/Mwh - $27.52/Mwh))	$ (34.0)
Capacity (196 Mw x 743 days x $82.26/Mw-Day)	(12.0)
Oyster Creek TPPA	
Energy (9,708 Gwh x ($38.99/Mwh - $35.29/Mwh))	(35.9)
Capacity (619 Mw x 723 days x $63.22/Mw-Day)	(28.3)
Additional Oyster Creek savings, Year 4	
Energy (3,232 Gwh x ($39.23/Mwh - $33.19/Mwh))	(19.5)
Cap. (imputed; 619 Mw x 243 days x $56.92/Mw-Day)	(8.6)
TMI-1 “Deal Strike Price Adjustments” (NPV)	(12.8)
Bayonne NUG restructuring	(25.4)
Disallowance	$152.5

SOURCES:

Exhibit S-32 (Company's response to S-JBGS-1), cost comparison, actual cost of discretionary purchases versus cost if purchased at "Sink Bus LMP" and "Weighted Average PJM Capacity Rate."

Exhibit S-36 (Company's response to S-RD-32), TMI-1, Oyster Creek and Sithe TTPA purchases and cost data.

Exhibit S-52 (Company's response to S-JMTC-2, incl. supplemental), year 4 Oyster Creek TPPA purchases and cost data for period August 2002 through March 2003.

Exhibit S-53 (Company's response to S-JMTC-3), TMI-1 "Deal Strike Price Adjustments"

- Discretionary purchases other than TPPAs exclude long-term (pre-transition period) PPAs with other utilities and NUGs.

- In determining the savings from the TMI-1 and Oyster Creek TPPAs relative to PJM, the average cost of each TPPA over the period it was in effect from Exhibit S-36 was compared to the average cost of the same energy and capacity (unadjusted for the underlying unit's forced outage rate) if purchased from PJM over the same period from Exhibit S-32.

- While the same analysis indicates the Sithe TPPA was about $28.1 million more expensive than purchasing the same capacity from PJM during the period the Sithe TPPA was in effect (November 7, 1999 through May 31, 2002; $28.1 million = 1,604 Mw x 937 days x ($67.18 - $85.90)), the Board's approval of the Sithe TPPA was not conditioned on a prudency review. Any such review would have to take into account a possible offset from the favorable effect a capacity only TPPA may have had on the sale price received for the divested fossil units. No adjustment was therefore made.

- The additional Oyster Creek energy savings in Year 4 of the Transition Period were taken directly from Exhibit S-47. The imputed capacity value was determined by pricing the Oyster Creek Mw-days at the average price paid for capacity during the period August 2001 through March 2002, from Exhibit S-32.

EXHIBIT 3

JERSEY CENTRAL POWER & LIGHT

DOCKET NO. ER02080506

Capital Structure and Weighted Average Cost of Capital

	Percentage Of Total	Cost Rate	WACC*
Long-Term Debt	47.77%	7.26%	3.47%
Tax Deductible Preferred	5.66%	9.24%	0.52%
Preferred Stock	0.57%	4.01%	0.02%
Common Equity	46.00%	9.50%	4.37%
	100.00%		8.38%

* Weighted Average Cost of Capital

Jersey Central Power & Light Company

Consolidated Tax Savings - Staff's Adjustment

	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	Cumulative	
JCP&L Taxable Inc/(Loss)	170,645,916	102,151,477	128,231,731	142,040,070	300,032,210	212,512,614	392,072,122	400,614,883	482,341,718		2,330,642,741	41.05%
Total Positive-Affiliate Taxable Income (1)	401,768,218	374,341,945	319,798,551	357,845,285	430,160,000	416,844,661	682,841,263	831,330,238	1,862,587,526		5,677,517,687	
Total Negative-Affiliate Taxable (Loss) (2)	(8,349,047)	(5,581,722)	(4,004,836)	(6,735,441)	(11,128,477)	(45,696,268)	(24,267,728)	(82,134,933)	(68,927,347)			
Statuatory Tax Rate	35%	35%	35%	35%	35%	35%	35%	35%	35%			
Consolidated Tax Savings	(2,922,166)	(1,953,603)	(1,401,693)	(2,357,404)	(3,894,967)	(15,993,694)	(8,493,705)	(28,747,227)	(24,124,571)			
Alternative Minimum Tax	0	0	0	0	0	0	0	0	0			
Total Net Savings	(2,922,166)	(1,953,603)	(1,401,693)	(2,357,404)	(3,894,967)	(15,993,694)	(8,493,705)	(28,747,227)	(24,124,571)		(89,889,030)	
JCP&L's % of Positive Affil. Tax Inc.											41.05%	
Tax Benefit - JCP&L											(36,899,791)	

Consolidated Tax Savings - RPA's Adjustment

	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	Cumulative
JCP&L Taxable Inc/(Loss)	170,645,916	102,151,477	128,231,731	142,040,070	300,032,210	212,512,614	392,072,122	400,614,883	482,341,718		
Total Positive Taxable Income (3)	404,274,324	375,228,895	324,843,082	366,080,154	457,168,143	422,538,127	705,057,362	867,830,114	1,902,106,134		
JCP&L's % of Positive Taxable Inc.	42.21%	27.22%	39.47%	38.80%	65.63%	50.29%	55.61%	46.16%	25.36%		
Non-Reg Tax Losses (4)	(10,839,085)	(6,452,100)	(9,035,847)	(14,965,129)	(38,134,625)	(51,387,738)	(46,481,830)	(118,632,811)	(108,443,956)		
JCP&L's share of tax loss	(4,575,224)	(1,756,505)	(3,566,898)	(5,806,510)	(25,027,150)	(25,845,106)	(25,847,868)	(54,764,255)	(27,499,540)		
Statuatory Tax Rate	35%	35%	35%	35%	35%	35%	35%	35%	35%		
Tax Benefit - JCP&L	(1,601,328)	(614,777)	(1,248,414)	(2,032,278)	(8,759,503)	(9,045,787)	(9,046,754)	(19,167,489)	(9,624,839)		(61,141,170)

(1) Sum of taxable income / (loss) during the year from affiliates with postive cumlative taxable income for the cumulative period.
(2) Sum of taxable income / (loss) during the year from affiliates with negative cumlative taxable income for the cumulative period.
(3) Sum of taxable income / (loss) during the year from affiliates with postive taxable income during the year.
s

Jersey Central Power & Light Company

Source Data

		1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	Cumulative
	Taxable Income /(Loss)											
	GPU, INC	(8,573,603)	(5,366,331)	(5,353,912)	(7,492,157)	(10,073,498)	(13,960,300)	(13,920,986)	(10,944,568)	(17,818,371)	(35,354,999)	(128,858,725)
	GPU Service Inc.	2,109,204	2,341,317	(2,151,132)	3,503,133	(10,129,538)	7,397,036	11,302,090	3,349,440	18,149,315	(30,546,572)	5,324,293
	GPU Nuclear Inc.	2,991,825	5,021,155	1,819,718	15,543,718	(8,735,804)	9,672,626	4,698,916	4,587,005	417,193	13,343,164	49,359,516
	General Portfolio Corp.	(3,876)	(28,632)	204,300	0	0	0	0	0	0	0	171,792
R	Jersey Central Power & Light	170,645,916	102,151,477	128,231,731	142,040,070	300,032,210	212,512,614	392,072,122	400,614,883	482,341,718	(278,586,515)	2,052,056,226
	JCPL Preferred Capital Inc.					193,262	1,421,957	1,502,217	1,615,606	1,672,873	1,688,555	8,094,470
	JCP&L Transition Inc.											0
	JCP&L Transition Holdings, Inc.											0
R	Metropolitan Edison Company	108,327,927	136,587,635	76,544,327	101,042,076	58,917,038	79,799,331	114,844,648	134,271,091	284,481,894	73,631,926	1,168,447,893
R	York Haven Power company	878,943	1,157,474	924,231	1,493,420	1,344,614	1,567,697	1,468,891	1,802,464	262,308	2,656,844	13,556,886
	Met-Ed Preferred Capital II Inc.									(11,858)	76,487	64,629
	Met-Ed Preferred Capital Inc.				87,103	195,395	1,168,906	1,261,784	1,363,965	1,070,932		5,148,085
R	Pennsylvania Electric Company	119,024,939	126,902,324	115,027,767	100,453,375	85,732,013	80,414,051	130,299,927	122,568,265	1,029,842,923	46,286,405	1,956,551,989
R	NinevehWater Company	(14,077)	(14,580)	(11,527)	(3,187)	293	10,616	14,774	12,738	4,800		(150)
	Penelec Preferred Capital II Inc.									(11,576)	(16,622)	(28,198)
R	Waverly Electric Light & Power											0
	Penelec Preferred Capital Inc.									574,767		574,767
R	Saxton Nuclear Experimental Corp.				115,230	199,056	1,239,422	1,330,350	1,440,129			4,324,187
	GPU Advanced Resources Inc.									(6,835,751)	(2,744,851)	(9,580,602)
	GPU Telcom Services Inc.						(519)	(6,470,485)	(4,565,704)	5,532,913	18,532,584	13,028,789
	GPU Diversified Holdings, Inc.						(519)	(102,284)	3,896,491			3,793,688
	GPU Enertech Holdings, Inc.										310,714	310,714
	GPU Genco						21,911,274	(346,800)	2,516,337	(3,514,647)		20,566,164
	GPU Power, Inc.					(3,138)	(644,512)	(1,258,007)	(2,627,982)	(404,190)		(4,937,829)
	Hanover Energy corporation										(2,528,321)	(2,528,321)
	Guaracachi America, Inc.					(68,999)	234,205	1,264,873	(1,531,393)	2,890,870	(1,022,180)	1,767,376
	El Barranquilla, Inc.					(4,187)	(267,066)	(385,209)	(1,302,467)	4,856,092	(758,237)	2,138,926
	Barranquilla Lease Holding, Inc.						102,775	1,142,313	2,839,265	5,046,828	5,251,400	14,382,581
	International Power Advisors, Inc.								166,666	1,611,462	1,670,014	3,448,142
	Austin Cogeneration Corp.											0
	GPU Power Philippines, Inc.											0
	GPU International Asia, Inc.							(148,349)	(191,178)	(398,552)	(35,587)	(773,666)
	GPU Power Ireland Inc.											0
	NCP Energy, Inc.										(87,385)	(87,385)
	NCP ADA Power, Inc.										(131)	(131)
	NCP Brooklyn Power, Inc.											0
	NCP New York, Inc.											0
	GPU Capital Inc.								(157,533)	(43,769,520)	(63,270,218)	(107,197,271)
	GPU electric, Inc.					(471,158)	(1,347,849)	(420)	(4,244,448)	(2,446,920)	(8,024,287)	(16,535,082)
	Victoria Electric, Inc.					(1,146,582)	(397,611)	6,575,248	51,987,015	8,471,168	(2,347,447)	63,141,791
	Victoria electric Holdings, Inc.						(2,116,000)	(4,617,981)	(17,126,221)	(7,061,424)	(6,326,384)	(37,248,010)
	GPU Australia Holdings, Inc.							(2,521,004)	(10,028,400)	(4,948,965)	(57,080,983)	(74,579,352)
	Austran Holdings, Inc.							(16,240,987)	(7,647,159)	(14,151,626)	(274,539,470)	(312,579,242)
	E.I. UK Holdings, Inc.						(20,195,409)	11,913,298	(31,010,792)	26,961,303	8,314,742	(4,016,858)
	GPU Brasil, Inc.											0
	VicGas Holdings, Inc.										(450,080)	(450,080)
	GPU Argentina Holdings, Inc.									1,185,603	3,433,255	4,618,858
	MYR Group, Inc.											0
	Comtel Technology Inc.										(491,136)	(491,136)
	D.W. Close Company, Inc.										(1,185,637)	(1,185,637)
	Great Southwestern Construction										1,018,378	1,018,378
	Harlan Electric Company										4,637,411	4,637,411
	Hawkeye Construction, Inc.										(60,259)	(60,259)

Jersey Central Power & Light Company

Schedule S-Rev-4

Source Data (Continued)

	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	Cumulative
MYR Com, Inc.										(1,434,650)	(1,434,650)
MYR Group, Inc.										(14,893,860)	(14,893,860)
MYR Power, Inc.										1,645,764	1,645,764
Power Piping Co.										(703,412)	(703,412)
Sturgeon Electric co.										9,913,046	9,913,046
The LE. Myers Co.										12,431,757	12,431,757
GPU International (form. EnergyInit.)	(2,206,056)	(707,936)	(1,530,803)	(4,209,307)	9,339,458	2,199,640	13,324,685	(25,453,166)	13,513,312	(3,771,461)	498,366
Elmwood Energy Corporation	288,581	(178,060)	1,156,550	1,290,388	234,693	149,329	1,690,545	3,571,540	1,200,132	(13,776,740)	(4,373,042)
Camichino energy Energy Corp.	(45,956)	(22,751)	204,053	159,309	3,654	(6,587,365)	166,324	(27,805)	2,606,924		(3,543,613)
Geddes cogeneration Corp.	(5,602)	(148,390)	728,412	(609,642)	(2,761,618)	(2,176,732)	5,025,772	112,526,533	2,391,355	8,601,903	123,571,991
Geddes II Corporation									141,367	7,484,956	7,626,323
El Selkirk, Inc.					(657,300)	604,575	879,061	3,074,991	3,366,260	79,193,564	86,461,151
El Fuels Corporation								156,895	521,030	377,242	1,055,167
El Services, Inc.								(60,392)	425,156	372,187	736,951
NCP ADA Power, Inc.				29,052	181,000	40,669	(2,717)	(478)			247,526
NCP Energy, Inc.				110,102	758,979	405,849	37,617	9,620,574	(2,687,811)		8,245,310
NCP Commerce, Inc.				(793,018)	(501,655)	(573,315)	1,076,733				(791,255)
NCP Lake Power, Inc.				9,370	34,483	(3,501)	(23,036)	(130,875)	(100,364)	(227,398)	(441,321)
NCP Gem, Inc.				201,814	(230,639)	(334,866)	(443,565)	(1,556,414)	(1,647,829)	(20,614,238)	(24,625,737)
NCP Dade Power, Inc.				(107,960)	(121,512)	(93,096)	44,933	(25,836)	(105,418)	369,644	(39,245)
NCP Pasco, Inc.				(1,753,045)	(3,228,997)	(2,689,078)	2,752,193	4,345,498	2,563,637	35,221,126	37,211,334
NCP Perry, Inc.						76,531	268,702	1,129,187	(1,127,037)	5,055,425	5,402,808
NCP Houston Power, Inc.						1,607,028	97,349	371,538	(1,167,550)	2,653,680	3,562,045
Northeast Energy Corp.	4,998	1,065,521									1,070,519
Northeast Cogen, Inc.	(3,992)										(3,992)
GPU Generation Serv.-Pasco									(234,547)	459,480	224,933
Total Taxable Income (Loss)	393,419,171	368,760,223	315,793,715	351,109,844	419,031,523	371,148,393	658,573,535	749,195,305	1,793,660,179	(476,247,407)	4,944,444,481
Total Tax Per Return	133,510,076	125,305,806	110,933,884	123,244,327	147,291,629	123,790,841	204,610,179	223,031,043	604,371,203	47,444	1,796,136,432

Source Data Calculations

	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	Cumulative
Tax Rate	35%	35%	35%	35%	35%	35%	35%	35%	35%	35%	
Taxable Income X Tax Rate	137,696,710	129,066,078	110,527,800	122,888,445	146,661,033	129,901,938	230,500,737	262,218,357	627,781,063	(166,686,592)	
Unspecified Adjustment	4,186,634	3,760,272	(406,084)	(355,882)	(630,596)	6,111,097	25,890,558	39,187,314	23,409,860	(166,734,036)	
sum where cumulative is positive	401,768,218	374,341,945	319,798,551	357,845,285	430,160,000	416,844,661	682,841,263	831,330,238	1,862,587,526	18,914,855	5,696,432,542
sum where cumulative is negative	(8,349,047)	(5,581,722)	(4,004,836)	(6,735,441)	(11,128,477)	(45,696,268)	(24,267,728)	(82,134,933)	(68,927,347)	(495,162,262)	
sum where number is positive	404,274,324	375,228,895	324,843,082	366,080,154	457,168,143	422,538,127	705,057,362	867,830,114	1,902,106,134	344,633,653	
sum where number is negative	(10,853,162)	(6,466,680)	(9,047,374)	(14,968,316)	(38,134,625)	(51,387,738)	(46,481,830)	(118,632,811)	(108,443,956)	(820,879,060)	
sum of non-reg where number is negative	(10,839,085)	(6,452,100)	(9,035,847)	(14,965,129)	(38,134,625)	(51,387,738)	(46,481,830)	(118,632,811)	(108,443,956)	(542,292,545)	
JCP&L's % of Positive Regulated	42.78%	27.85%	39.98%	41.15%	67.24%	56.59%	61.26%	60.63%	26.84%	-227.28%	

Regulated Utility Data

		1,991	1,992	1,993	1,994	1,995	1,996	1,997	1,998	1,999	2,000	Cumulative	
R	Jersey Central Power & Light	170,645,916	102,151,477	128,231,731	142,040,070	300,032,210	212,512,614	392,072,122	400,614,883	482,341,718	(278,586,515)	2,052,056,226	39.50%
R	Metropolitan Edison Company	108,327,927	136,587,635	76,544,327	101,042,076	58,917,038	79,799,331	114,844,648	134,271,091	284,481,894	73,631,926	1,168,447,893	22.49%
R	York Haven Power company	878,943	1,157,474	924,231	1,493,420	1,344,614	1,567,697	1,468,891	1,802,464	262,308	2,656,844	13,556,886	0.26%
R	Pennsylvania Electric Company	119,024,939	126,902,324	115,027,767	100,453,375	85,732,013	80,414,051	130,299,927	122,568,265	1,029,842,923	46,286,405	1,956,551,989	37.66%
R	NinevehWater Company	(14,077)	(14,580)	(11,527)	(3,187)	293	10,616	14,774	12,738	4,800	0	(150)	0.00%
R	Waverly Electric Light & Power	0	0	0	0	0	0	0	0	0	0	0	0.00%
R	Saxton Nuclear Experimental Corp.	0	0	0	115,230	199,056	1,239,422	1,330,350	1,440,129	0	0	4,324,187	0.08%
	Regulated Income	398,877,725	366,798,910	320,728,056	345,144,171	446,225,224	375,543,731	640,030,712	660,709,570	1,796,933,643	122,575,175		
	Regulated (Losses)	(14,077)	(14,580)	(11,527)	(3,187)	0	0	0	0	0	(278,586,515)		
	Total Regulated	398,863,648	366,784,330	320,716,529	345,140,984	446,225,224	375,543,731	640,030,712	660,709,570	1,796,933,643	(156,011,340)	5,194,937,031	100.00%

Source: Source Data & Regulated Utility Data = RAR-RR-75
Staturatory Tax Rate = R-38, Exhibit (DEP-1), Schedule 2, Page 3